Ontario Energy Board Commission de l'énergie de l'Ontario

Ontario

Market Surveillance Panel

Congestion Payments in Ontario's Wholesale Electricity Market: An Argument for Market Reform

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Executive Summary

Since market opening, no element of Ontario's wholesale electricity markets has attracted the attention and concern of the Market Surveillance Panel (Panel) more than Congestion Management Settlement Credit (CMSC) payments. These payments, a fundamental adjunct of Ontario's uniform price/two schedule market design, have resulted in inefficiencies and inappropriate wealth transfers, and have shown themselves to be susceptible to gaming.

This report provides a retrospective of Ontario's history with CMSC payments. It notes issues that have arisen over the years, and actions that the Independent Electricity System Operator (IESO) has taken to address a number of the Panel's concerns in whole or in part. Although little in this report is new, the Panel believes that publication of its report at this time is opportune, given the IESO's recent decision to embark on a broad Market Renewal initiative that holds promise in terms of a re-design of the market.

The Panel supports the replacement of the uniform price/two schedule market design with a design that would facilitate future market renewal and rely less on out-of-market payments like CMSC payments. In particular, the Panel believes that some form of locational pricing should be introduced, whether for market participants only or for residential and other smaller volume consumers as well. This report uses CMSC payments as a case study to illustrate and reinforce the need for – and importance of – fundamental market reform.

Chapter 1: Introduction

Ontario's wholesale electricity market has been operating for 14 years now and the Market Surveillance Panel (the Panel) has been actively engaged in monitoring its development for even longer. No other subject has garnered as much of the Panel's attention and concern as the uniform price/two schedule market design (the Two Schedule System) and its associated congestion management settlement credit (CMSC) payments regime. Although originally intended to be a temporary feature of the wholesale markets (the IESO-administered markets), CMSC payments have endured. Annual CMSC payments since market opening average $110 million per year with total CMSC payments over the life of the market exceeding $1.5 billion.

While the Panel has in the past called for the replacement of the Two Schedule System, much of its work has been directed to analysis of specific problems with the CMSC regime such as the inefficiencies, inappropriate wealth transfers, and gaming opportunities it gives rise to. With the Independent Electricity System Operator (the IESO) embarking on a major market renewal initiative, the Panel considers that it is opportune to leverage its years of commentary to lend its renewed support for the replacement of the Two Schedule System with a design that would rely less on complex and non-transparent out-of-market payments like CMSC payments.

In particular, the Panel believes that some form of locational pricing should be introduced. An electricity market design with locational pricing is one where different market participants pay or are paid different prices for electricity depending on where they are located on the grid. This better reflects the fact that the true cost of supplying electricity is different at different places on the grid. Ignoring this reality causes inefficiency and gives rise to complex work-arounds like CMSC payments. In consideration of historic concerns, it is entirely possible to realize much of the efficiency benefits of a move to locational pricing by applying it only to the most sophisticated market participants – dispatchable generators and loads – while keeping small volume and residential consumers on a uniform price.

The IESO has shown a strong interest in advancing fundamental market reform as demonstrated by its several recent market design-oriented consultations:[1]

- Market Renewal (*SE-Market Renewal*, launched March 2016)
- The Capacity Auction Review (*SE-Capacity*, launched April 2014)
- The Energy Market Pricing Review (*SE-114*, launched August 2013)
- The HOEP Review (*SE-105*, launched November 2012)
- The Global Adjustment Review (*SE-106*, launched November 2012)

The most recent of these consultations, Market Renewal, is actively considering alternatives to the Two Schedule System; as well as giving consideration to a day-ahead market, a single schedule market design, and a capacity market. There are benefits to Ontario that can be achieved through a day-ahead market design,[2] but these cannot be realized within the context of a Two Schedule System.[3] In this sense, the continuation of the Two Schedule System is a barrier to future market renewal.

Many market participants may well have become invested in preserving and defending the current design as a result of the extra income that can be obtained in the form of CMSC payments. However, as discussed later in this report, many of the most problematic issues associated with the CMSC regime have been brought to an end – in large measure as a result of the Panel having identified these situations, and the IESO having acted to eliminate them. The Panel expects that a more fundamental reform away from the Two Schedule System will be easier as a result.

In addition, almost all of Ontario's generators are now subject to contracts or regulated pricing that reduce their exposure to spot prices.

[1] The details of these and other stakeholder engagements are available on the IESO's stakeholder engagement webpage at http://www.ieso.ca/Pages/Participate/Stakeholder-Engagement/default.aspx.
[2] One of many potential benefits is better coordination of Ontario's export and import of electricity with neighbouring jurisdictions.
[3] There are also reasons to believe that the full benefits of a capacity market cannot be achieved without locational pricing. However, while moving to a single schedule system design is a clear aim of Market Renewal, the IESO has indicated that such a move will not necessarily include locational pricing.

1 Structure of this Report

The following is an overview of the remaining chapters of this report. A glossary of terms and acronyms is provided at the end of the report.

1.1 Chapter 2: The Essentials of the Argument

This chapter leverages the Panel's past commentary on CMSC to highlight why the Panel believes that the Two Schedule System should be replaced with a locational marginal pricing design. The following three chapters provide a more detailed review and summary of past Panel commentary and analysis that underscores the need for redesign.

1.2 Chapter 3: A Review of the Data

This chapter tells the story of the numbers. It examines trends in total CMSC payment amounts and breaks these totals out into their most interesting component parts, including constrained-off versus constrained-on CMSC payments. It also discusses the extent to which CMSC payments have been driven by transmission congestion versus the extent to which CMSC payments have been made for other reasons.

1.3 Chapter 4: Unwarranted Transfers, Inefficiency, and Gaming

This chapter summarizes some of the Panel's past work on the inefficiencies, wealth transfers and gaming opportunities found in the Two Schedule System.

1.4 Chapter 5: Systemic Problems in the Northwest

The wedge between locational prices[4] and the uniform price is largest in the Northwest. Almost one third of all CMSC payments have gone to participants either located there or engaged in trading energy at the Northwest's interties. This is the case despite the very small percentage of Ontario's wholesale market participants located in the Northwest. This chapter explores the reasons for these outcomes and the attempts that have been made to ameliorate them.

[4] "Locational prices" are calculated at individual "nodes" or connection points on the grid where a distinct cost of supplying electricity can be measured. These "nodal prices" are used to help coordinate the dispatch of generation and the consumption of dispatchable loads but are not used as settlement prices in Ontario's Two Schedule System. In a locational pricing design these prices are used for settlement.

Chapter 2: The Essentials of the Argument

This chapter leverages the Panel's years of commentary on the Two Schedule System and CMSC payments in order to support the argument for replacement of the Two Schedule System. Chapters 4 and 5 provide some of the background support to these arguments as found in previous Panel commentary.

2.1 *The Two Schedule System does not reflect the realities of the transmission grid*

The fundamental problem with the Two Schedule System is its lack of adherence to the realities of the transmission grid.

The cost of supplying electricity is different at different places on the grid. This is, in part, a reflection of line losses – the further electricity is transmitted from its generation source, the more that is dissipated as waste heat, and the less that is available for withdrawal by a consumer. The greater the "electrical distance" between the producer and consumer, the higher the cost of satisfying that consumption.

It is also a reflection of transmission congestion. When the energy flow along a given transmission line is at that line's capacity, but demand continues to grow, the system operator must use a more expensive but technically feasible way of meeting demand.[5] For example, this could mean constraining on a more expensive generator that has easier transmission access to the consumer, and constraining off the generator that had lower production costs but whose output threatens to overload the transmission line. This raises the cost of supplying electricity at that consumer's location.

The dispatch algorithm is the computer program that coordinates the system so as to minimize the cost of meeting demand while not violating transmission constraints. The dispatch algorithm produces the dispatch schedule – one of the two schedules in the Two Schedule System. It calculates the cost of supplying electricity at each location on the grid. In a locational marginal pricing (LMP) market design these locational costs are used as settlement prices. The true cost

[5] This is known as "redispatching generation away from the merit order". See the Glossary discussion of the term "merit order" – basically the market schedule supply curve – for a graphical depiction of the market schedule / dispatch schedule distinction.

of supplying electricity is reflected in the prices for consumption and production at different points on the grid.

However, in the Two Schedule System, a market algorithm coexists with the dispatch algorithm. The market algorithm determines a market schedule of production and consumption; these schedules are notional in that they are for settlement purposes only, and are not to be followed by the resource.[6] The grid cannot feasibly accommodate the market schedules because the the market algorithm that produces them assumes there are no congestion constraints.[7] For the purpose of settlement, every five minutes the market schedule optimizes offers to sell power and bids to buy it to determine a uniform Market Clearing Price (MCP) that prevails over the entire grid. All internal market participants pay or are paid the MCP, regardless of their location in the province. The MCPs are averaged each hour into the Hourly Ontario Energy Price (HOEP).

Thus the market algorithm assumes that demand anywhere on the grid can be met by the most economical generation (or dispatchable load) source, no matter where it is located on the grid. This assumption is not true when there is transmission congestion. In the Two Schedule System the market schedule sets the price and in essence does so using "fictional supply":

> *We do not see how a market design that uses fictional resources to lower the benchmark price contributes to market efficiency...*[8]

2.2 *What is CMSC?*

CMSC is an out-of-market payment[9] that is a feature of the Two Schedule System. This market design is one approach to the management of transmission congestion on a bulk electricity grid,

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[6] Each dispatchable generator and load receives two "dispatch" instructions every five minutes giving quantities for production or consumption. One is the market schedule instruction and the other is the dispatch schedule instruction. If a generator's dispatch schedule amount is greater than its market schedule amount it is "constrained on". Its actual output must conform to the dispatch schedule instruction. See the Glossary for more on "constrained-on" and "constrained-off" dispatch instructions.

[7] In the Ontario real-time energy market the market algorithm assumes away all internal congestion constraints but allows for them at the interties with neighbouring jurisdictions. A version of LMP pricing is currently used at the interties.

[8] Market Surveillance Panel Discussion Paper, *Congestion Management Settlement Credits (CMSC) in the IMO-Administered Electricity Market: Issues related to constrained off payments to generators and imports*, February 2003, page 12, available at http://www.ontarioenergyboard.ca/documents/msp/consultation_discussionpaper_180203.pdf.

with CMSC payments compensating resources for divergences from their economically optimal level of generation or consumption.[10]

More specifically, the original intent of CMSC was to incent dispatch compliance and maintain reliability given the uniform price. CMSC payments induce dispatch compliance by returning return participants to the profits or benefits they would have earned, had transmission congestion not prevented them from producing or consuming their market schedule quantity.[11]

The original reliability basis for CMSC payments has led to at least two of the Panel's long-standing concerns with the Two Schedule System:

- In the Panel's view, a large portion of CMSC payments (in particular, constrained-off payments for suppliers) are not needed to ensure dispatch compliance and maintain reliability; and
- The Two Schedule System exhibits "mission creep". Additional rationales for the payment of CMSC have accumulated over the years, and these rationales do not relate to the original intent of CMSC. In the Panel's view, CMSC is an inappropriate means to achieve these other objectives to which, over the years, CMSC has been assigned.

2.3 *Inefficiency Induced by the Two Schedule System*

It was known from the outset based on experience elsewhere that uniform pricing would result in inefficiencies and distortions in the market that would require a number of administrative fixes. Nevertheless this was considered acceptable as a temporary measure.[12]

[9] Out-of-market payments are common in organized electricity markets. By nature they are not part of the market price and hence are a less transparent means of compensation to market participants. There are several categories of out-of-market payments in the IESO-administered markets, including: CMSC payments, generator cost guarantees, and intertie offer guarantees. All are designed to compensate market participants in various situations when the market price is viewed as providing insufficient compensation, and hence not sufficiently promoting reliability. Unless well designed, out-of-market payments can lend themselves to being exploited by market participants.

[10] Among organized electricity markets worldwide, Ontario is, to the best of our knowledge, alone in using this Two Schedule System to price electricity and manage congestion.

[11] See the Market Design Committee *Final Report*, January 29, 1999, page 3-8, available at http://www.ieso.ca/Documents/mdc/Reports/FinalReport/Volume-1.pdf.

[12] Market Surveillance Panel June 2006 Monitoring Report, pages 121-122, available at http://www.ontarioenergyboard.ca/documents/msp/msp_report_final_130606.pdf.

2.3.1 *General Inefficiency*

In Ontario's Two Schedule System the same settlement price – the HOEP – applies to all consumers and producers, regardless of location. For example, transmission constraints limit the amount of low-cost generation that can be transmitted to southern Ontario from the northern regions of the province. Higher cost generation in the south makes up the difference, but consumers are still charged the HOEP - as if the lower cost supply could actually reach the south. Thus there will be a tendency towards inefficiently high consumption in the south. Meanwhile, in the north, consumers are charged the same uniform price despite the availability of low-cost generation nearby. They will therefore be induced to consume less than the efficient amount.[13]

The Panel has not attempted to measure this inefficiency beyond noting its pervasive nature.

2.3.2 Intertie Inefficiency

The general inefficiency described above is on display more vividly in transactions that occur at Ontario's interties with neighbouring jurisdictions. In this context, inefficient trade transactions generate an observable trail of purchase price, delivered price, and true production cost. For example, the Two Schedule System allows exporters to buy energy at Ontario's uniform price and export it to a neighbouring jurisdiction, even if the cost to generate that energy – as measured by the nodal price nearest the intertie – is above the uniform price. Thus energy that costs more for Ontario to produce than it is sold for in, say, New York, can still yield a profit to the exporter as it only pays Ontario's uniform price for the export.

The Panel has analyzed this form of inefficiency in several of its semi-annual Monitoring Reports, including its recently published November 2016 Monitoring Report. As with the general inefficiency discussed above, this sort of inefficiency is pervasive on the interties.

2.3.3 Dynamic or Investment Inefficiency

Where should new generation be added to the system? Where is it most sensible to expand electricity consumption by large industries, and where should reinforcements to the transmission grid be made? There are a large number of factors that go into answering these questions, and

[13] What economists call "allocative efficiency" is attained when consumers' marginal benefit of consumption reaches equality with the marginal costs of production. However if the prices do not accurately reflect marginal costs then regional consumption and production decisions will fall short of allocative efficiency.

the cost of supplying electricity at different locations on the grid is only one of them. However, to the extent that the price and true cost of electricity matters to the answers, the Two Schedule System will yield misleading signals.

Efficient price signals would steer generation investment to areas where only high cost generation is available and transmission constraints prevent less costly generation from being transmitted there. These price signals would steer industrial consumers of energy in the opposite direction. Additionally, efficient price signals facilitate assessments of the relative value of transmission upgrades (to relieve transmission constraints) versus generation investments and/or other congestion solutions. However, the Two Schedule System with its CMSC payments does not provide these signals, and in fact can generate signals that induce investment in the wrong places.

In Ontario these decisions (at least for generation and transmission) are currently made via central planning processes, and site selection therefore does not necessarily reflect private profit-driven behaviour. However, the IESO is now considering the adoption of a capacity market which would tilt these decisions back towards a more decentralized, investor-driven model. Under this scenario the incentive problems with the Two Schedule System and CMSC payments will loom larger. If private investors play a stronger role in determining where investments are made, it becomes more important that they are exposed to price signals that accurately reflect the value of electricity at different locations, and that investors are not unduly influenced by the availability of out-of-market CMSC payments.

2.4 *Wealth Transfers and Gaming of CMSC Payments*

> *The MSP is concerned that some aspects of the congestion management payment system appear to be conducive to gaming, and will monitor behaviour in these areas closely.* [14]

This concern was expressed before the Ontario electricity market opened in May 2002. It reflects a looming question about the Two Schedule System and how participants might influence the amounts of CMSC payments that are made to them via changes to their offer or bid

[14] Backgrounder, *The Market Surveillance Panel in Ontario's Electricity Market: Monitoring, Investigating, and Reporting*, April 2002, available at http://www.ieso.ca/Documents/marketSurv/ms_MSP_Backgrounder.pdf.

prices, or to other aspects of their market and operating behaviour. These concerns were more than borne out in the actual evolution of the market as Chapters 4 and 5 will show. For now we will cover the features of the market design, or specific aspects of the market rules, that have enabled market participants to induce large CMSC payments at the expense of the market as a whole.

2.4.1 Assumptions on Offering at Marginal Cost and Bidding at Marginal Benefit

When the Panel carries out an investigation into behaviour that might be gaming, it uses a framework set out in its first published gaming investigation reports from 2012.[15] A key aspect of the framework is the notion of a market defect which can be exploited by a market participant. A key market defect that the Panel has identified in its CMSC gaming investigations is the assumption in the market rules that generators offer to sell energy at a price equal to their marginal cost of production, and dispatchable loads bid to buy energy at a price equal to their marginal benefit of consumption.[16]

If these assumptions were true then the CMSC calculation formulas would be closer to approximate measures of the lost profit or benefit resulting from congestion on the grid. CMSC payments would offset these losses and gaming and inappropriate wealth transfers would be less of a concern.

However, there is nothing guaranteeing that offer and bid prices are based on these values. Economists expect producers to offer at marginal cost (and consumers to bid at marginal benefit) only when competitive pressure forces this behaviour. In other words, a producer will be inclined to set their offer price at marginal cost only if setting a higher price will result in a rival producer taking away the sale. Similarly a consumer will bid at their marginal benefit of consumption only when bidding a lower price runs the risk that the purchase will be lost to a rival buyer.

[15] The Panel's investigations are discussed more fully and cited in Chapter 4. Gaming was also discussed in the Panel's *Monitoring Document: Monitoring of Offers & Bids in the IESO-Administered Electricity Markets*, March 2010,available at http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Monitoring_Offers_Bids_Document_20100310.pdf However, the investigation reports contain a more complete articulation of the gaming investigation framework.
[16] These assumptions are stated in the Market Rules, Chapter 7, Appendix 7.5 The Market Clearing and Pricing Process, page 7.5-13, available at http://www.ieso.ca/Documents/marketRules/mr_chapter7appx.pdf.

As later chapters will show, market participants are frequently insulated from competition and can set offer and bid prices that may be far different from any reasonable measure of marginal cost or benefit. Thus the participants can self-induce large CMSC payments that do not serve any efficiency or reliability purpose.

The Panel has analyzed and commented on other market defects as discussed in the following sections.

2.4.2 Other Market Defects: CMSC Payments for Any Schedule Difference

The CMSC regime automatically pays CMSC to a market participant whenever the participant's market and dispatch schedule differ, even if the cause of the difference has nothing to do with transmission congestion. For example, whenever a unit is changing from one output (or consumption) level to another, known as "ramping",[17] its two schedules will automatically differ as the market schedule multiplies the true ramp rate by 3-times (explained below). Also, if a participant simply opts to hold its unit at a level of output (or consumption) different than its dispatch instruction, it induces a market vs. dispatch schedule difference and will receive a CMSC payment.

2.4.3 Other Market Defects: Ramp Rate Assumptions

Prior to market opening, during the market's testing period analysts noted a high degree of price volatility brought about by the insufficient ramping capability of the Ontario generation fleet. For example, suppose a slower ramping fossil-fired generator is currently the marginal supplier. If an additional 200 MW of output was required to meet demand by the end of the next 5 minute interval, it was frequently the case that there was not enough ramping capability at online fossil-fired generators to increase output that fast. Thus the ramp constrained generators would be scheduled to the maximum permitted by their ramping constraints, while higher-priced peaking hydro units were scheduled to meet the remaining demand. Scheduling increasingly expensive generation would increase the market price and add to price volatility.

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[17] The offers and bids submitted by dispatchable generators and loads must contain "ramp" information – indications of how quickly production or consumption can be changed from one level to another. Ramping capability is an important aspect of balancing supply and demand in the market.

The IESO decided to mitigate price volatility in the market algorithm by treating generators and dispatchable loads as if they could ramp 12 times faster than they indicated they actually could.[18] Thus in the scenario above, the market algorithm would dispatch the now faster-ramping fossil units to meet increasing demand, with no big spike in price. The dispatch algorithm would, however, use actual ramp rates and continue to dispatch the peaking hydro facilities. The hydro facilities would be constrained on and receive constrained-on CMSC; the slow-ramping fossil units would receive constrained-off CMSC payments. Thus the differing ramp rate assumptions in the market and dispatch algorithms would result in market and dispatch schedule differences – and CMSC payments – whenever a dispatchable participant was ramping.[19]

Why is the ramp rate assumption a market defect? It creates a situation where dispatchable generators and loads can influence the size of the CMSC payments they receive via simple changes to their offer and bid prices. As Chapter 4 will show, the ramp rate assumption gave rise to the ramp-down CMSC problem – one of the most significant self-induced CMSC problems the market has seen.

Together, these market defects have provided market participants with substantial opportunities to induce large CMSC payments for themselves.

2.4.4 Wealth Transfers: The IESO's SE-114 Stakeholder Engagement

Although wealth transfers are not, in and of themselves, a problem from an efficiency standpoint, the Panel has often drawn attention to the extent of such transfers that the Two Schedule System enables. One of the IESO's market evolution activities sheds light on this topic: the IESO's Energy Market Pricing Review stakeholder engagement exercise and its final report provided by the IESO's consultant, Market Reform.[20] That report examines three alternatives to the Two Schedule System and how they might save Ontario consumers money; providing cost/benefit estimates for all three options over a ten year horizon. The option that achieves the highest net present value is a Locational Marginal Price (LMP) design. This option generates benefits of

[18] Thus the market schedule, which already used "fictional" bottled supply to meet actual demand, began to also use "fictional" ramp rates to meet increasing demand.
[19] In 2007 the 12-times ramp rate assumption was changed to a 3-times assumption where it remains today.
[20] See Market Reform, *Energy Market Pricing Review: Final Report Version 1.0*, February 19, 2015, available at http://ieso-public.sharepoint.com/Documents/consult/se114/SE114-20150219-Final_Paper.pdf.

$260.4 million with an implementation cost of $133.2 million for a net present value of $127.1 million.

These "benefits" represent transfers from dispatchable participants (mainly generators, but also dispatchable loads and traders) to Ontario consumers. Therefore this study usefully highlights the magnitude of transfers brought about by the Two Schedule System – transfers that the Panel views as in many cases unwarranted from an efficiency or reliability perspective. However, as the study focusses on transfers alone it is not really a cost benefit analysis. A true cost benefit analysis would demonstrate efficiency gains above and beyond the transfers to consumers that would result from an LMP design.

It is important to note that this estimate does not consider any gains to short-term efficiency – the report acknowledges that there are efficiency gains to be had but, for the purpose at hand, assumes that offering and bidding behaviour are the same in all options considered, and thus dispatch is the same. Furthermore, long term efficiency – the path of optimal investments in the industry – is the same in all options. Thus the calculated benefits of the LMP design are limited to reducing unnecessary wealth transfers realised primarily by the elimination of CMSC payments.

Regarding offering and bidding behaviour, the study assumes that, under the current Two Schedule System design, all participants act in accordance with the implied assumptions of the CMSC regime – offering at marginal cost, and bidding at marginal benefit – an assumption the Panel has identified as a market defect. The study goes on to estimate the extra CMSC that could be garnered if participants optimally implemented strategic offering and bidding behaviour aimed at maximizing CMSC payments.[21] Market Reform estimates that such strategic behaviour could amount to an additional $364 million in CMSC payments, although it notes that market uncertainty and the difficulties in achieving optimal strategic bidding would likely result in 10% of the potential $364 million being paid. The Panel's analysis of the Energy Market Pricing Review's Final Report (given in its October 2015 Monitoring Report) provides strong reasons to

[21] See Chapters 4 and 5 for discussions of some of these strategic behaviours.

suspect that this study's estimates of the benefits to consumers from a move to LMP would probably be much higher than the amounts estimated here.

Many Small Winners, A Few Big Losers

As noted above, the 2015 report prepared by Market Reform studies the wealth transfer aspects of CMSC payments - one person's gain is another person's loss. In other words, the study focusses on how one specific group, Ontario consumers, will benefit from a move to LMP.

This is a large group of people, very few of who have any understanding of how a revised market design would benefit them. While the benefits to the group as a whole would be substantial, the benefits per person would be less significant.

The "losers" from a revised market design are, on the other hand, highly sophisticated and know how such a redesign will impact them. Losers naturally resist changes that will harm their interests, and are well positioned to slow down such changes. This is without a doubt a factor in explaining how long it has taken to make some of the piecemeal changes to market rules that have mitigated the flow of CMSC payments.

2.5 *Mission Creep – CMSC has been assigned more tasks than it was designed for*

The problem of many small losers and few big winners has likely contributed to CMSC "mission creep" – the tendency for additional reasons to make CMSC payments to accumulate over time - with new arguments as to why it is necessary or justified.

The Panel first commented on the accumulating number of arguments for CMSC payments in its 2003 consultation on constrained-off CMSC and found that none of them were justified.

2.5.1 The 2003 CMSC Consultation

The Panel's February 2003 discussion paper that launched its 2003 CMSC consultation noted that, while there is a clear rationale for constrained-on CMSC for generators and loads in the context of a uniform price market design, the rationale for constrained-off payments was much more difficult to discern. The Panel identified five arguments that had been put forward at the time but found all of them wanting. In some cases, these arguments strayed a considerable distance away from anything to do with transmission congestion and reliability. The following summarizes these arguments, the Panel's responses, and other aspects of the CMSC debates.

> ***Argument #1: Constrained-off payments provide a market clearing price reduction service to Ontario loads. The uniform price design uses a market schedule algorithm to determine the market clearing price assuming no internal congestion constraints. Thus, bottled generation that is not able to reach market is nevertheless scheduled in the market schedule. This drives the price lower than it would otherwise be. This price reducing service is valuable to loads, and constrained-off CMSC is an appropriate compensation for this service.***

In the Panel's view, using what is essentially fictional supply to set the MCP is inimical to efficient resource use. Normal market signals on the scarcity value of electricity, and on the value of generation investment, are clearly distorted by such an approach. In a locational pricing design, appropriate price signals would be guiding consumption and investment decisions around the grid. Thus in areas with bottled generation, locational prices would be naturally lower, encouraging consumption and discouraging additions to supply.

> ***Argument #2: Constrained-off payments provide cash flows to bottled generators not having assured market access. Thus these payments provide financial viability to these generators and as a result bolster reliability.***

In the Panel's view, this function is not part of the mission of CMSC payments. Efficiency and reliability would be better served by more targeted approaches, such as the use of reliability must run contracts, or the capacity market that is now under development by the IESO. It would only be by chance that CMSC payments would provide the level of financial support that reliability concerns could justify. In a locational pricing design, the prices generators receive in a region with bottled supply would be fully transparent and therefore helpful in designing financial viability solutions such as reliability must run (RMR) contracts.

> ***Argument #3: Constrained-off payments play a useful role in signaling where transmission capacity needs to be upgraded.***

This argument does have some conceptual appeal but faces a major practical difficulty: as we will see, it is very difficult to separate CMSC payments into transmission congestion-related payments, and payments caused by other drivers such as self-induced CMSC and gaming. The nodal prices that actually govern the dispatch of the system are in most cases a better signal of transmission congestion – CMSC is not needed nor intended for this role. These nodal prices would be an even better signal of potentially needed transmission or generation investments in an LMP design where the opportunity to target CMSC via strategic offering and bidding prices is absent.

Argument #4: Constrained-off payments provide participants with an incentive to comply with dispatch instructions. Without constrained-off payments, a generator may opt to provide supply when told not to.

In the Panel's view this is a compliance issue. Compliance with dispatch instructions is essential for the market to operate safely and reliably, which is why market rules already exist that require market participants to follow dispatch instructions, or risk possible sanctions. And, as we will see in Chapter 4, the Panel has noted instances where CMSC payments were self-induced by means of dispatch deviations.

Argument #5: CMSC compensates for "initial endowments". Siting decisions made for generation in the era of Ontario Hydro's integrated public monopoly did not reflect the forces of a competitive marketplace. Thus while these decisions may have provided efficiency and reliability benefits to the whole province, they did not take into account financial viability in a market setting. CMSC payments provide this financial viability.

This argument is quite similar to the one above concerning the financial viability of bottled generators. In the Panel's view there is no strong rationale for the use of CMSC payments to compensate generators for the opening of the market. Even if there was such an argument, it would only apply to generators that existed at the opening of the market and not newer ones. In any case, more properly targeted means, such as RMR contracts, could be found to provide financial viability when needed.

2.5.2 More Recent Arguments for CMSC Payments

Two additional arguments were made recently in the final report of the IESO's consultation on efficiency of the HOEP,[22] and in the IESO's response to a Panel recommendation on ramp-down CMSC made in its April 2012 Monitoring Report.[23]

> ***Supplementary Argument #1: Without constrained-off CMSC payments generators in a constrained down region (like the Northwest) would reduce their offer prices to very low levels in order to compete for dispatch, knowing that in the uniform price design they will be paid the HOEP in any case.***

In the Panel's view, generators in the Northwest seem to have little preventing them from making low and negative offer prices; in fact this is already prevalent under the Two Schedule System design. Under a locational pricing design with no CMSC payments, there would be little incentive for generators to offer prices below their marginal costs as they would run the risk of realizing those prices as their settlement prices.

> ***Supplementary Argument #2: The remaining CMSC may well be consistent with the cost of efficiency losses that generators incur when ramping down and that removing ramping down CMSC from generator revenues would require an alternate mechanism to allow for generators to recover legitimate losses.***

However, to the extent that generators do incur higher costs when ramping down, it would only be by chance that CMSC accurately offsets these costs, especially when, as will be discussed later, generators can self-induce very large CMSC payments during ramp-down.

The arguments and scenarios critiqued above provide examples of what the Panel views as CMSC "mission creep" – an accumulation over time of rationales offered for the continuation of

[22] See Scott Harvey, *Review of the Efficiency of the Hourly Ontario Energy Price: Final Report*, July 24, 2013, available at http://ieso-public.sharepoint.com/Documents/consult/se105/se105-20130724-review_efficiency_hoep.pdf. This report concluded the IESO's SE-105 stakeholder engagement on the review of the HOEP.

[23] See the June 20, 2012 letter from Paul Murphy, President and Chief Executive Officer, IESO, to Rosemarie Leclair, Chair, OEB, available at http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/IESO_Response_to_Chair_MSP_20120620.pdf.

the CMSC regime. In the Panel's view, none of these arguments have a valid underpinning in an efficiency or reliability benefit to the market.

Later chapters will provide more background on some of the scenarios where CMSC "mission creep" has been observed.

2.6 *Moving to LMP will not save all of what CMSC currently totals*

The Panel acknowledges that even if CMSC is nominally eliminated in a move to an LMP design, some of the same amounts paid would still be paid but in other more legitimate forms.

In an LMP market design, regions where generators tend to be constrained on would exhibit higher locational prices. These would be paid to all generators in the region – not just those who would be constrained on in a Two Schedule System. So some of what is now paid as CMSC will transfer to higher settlement prices paid to all generators in a given region.

However, these settlement prices would be more accurate market signals as to the locational value of generation in the region in question. These market signals will be consistent with more efficient levels of electricity production and consumption.

Additionally, as discussed above, some CMSC payments that serve to maintain the financial viability of generators needed for reliability purposes would re-emerge in other forms, such as RMR contracts.

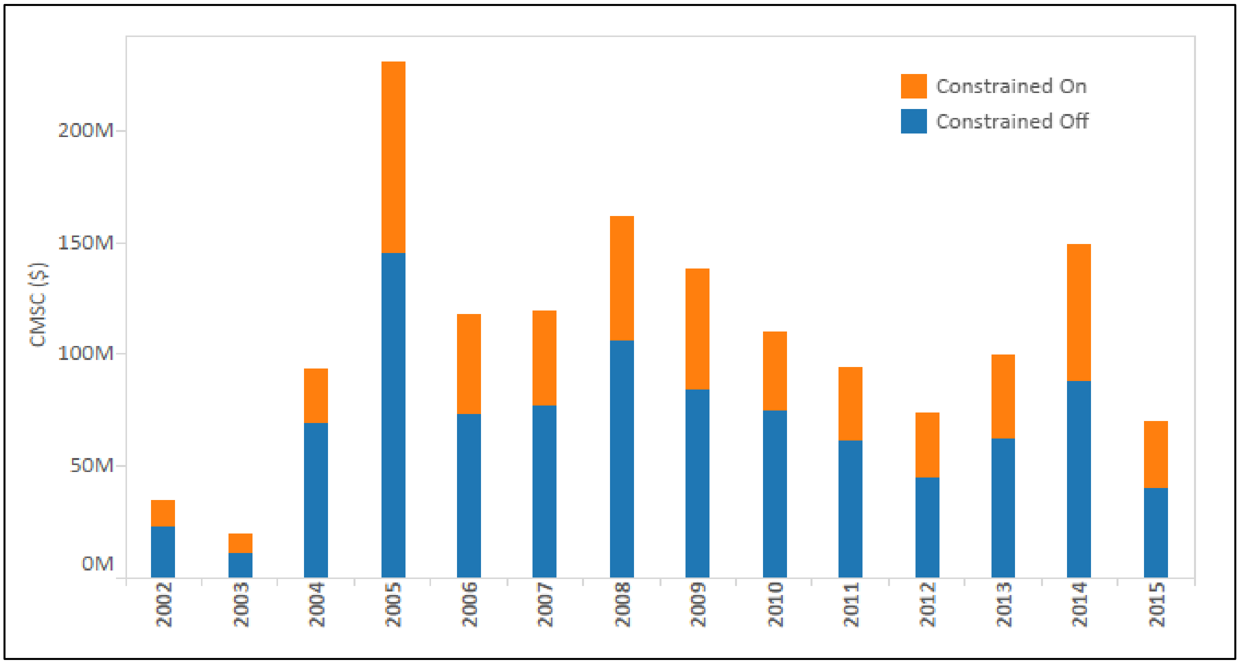
Chapter 3: A Review of the Data

3.1 *CMSC in Aggregate*

Net CMSC[24] totals more than $1.5 billion from market opening through 2015. Of this total $958 million (or 63%) are constrained-off payments while $553 million (or 37%) are constrained-on.

CMSC has averaged $110 million per year, however this average hides considerable variability from year to year. Figure 3-1 below shows total net CMSC divided into constrained-off and constrained-on components.

Figure 3-1: Total Net CMSC
May 2002 – December 2015
($ millions)



The year 2005 saw the largest total CMSC payments at $230 million. This year also saw the largest demand for energy of any year since market opening.

[24] The CMSC numbers in this report are all net of clawbacks of CMSC payments via measures such as the local market power and Constrained-Off Watch Zones (COWZ) provisions of the market rules. These provisions are intended to limit unwarranted CMSC payments, but, in the Panel's view do not go nearly far enough. The CMSC data here is also net of any negative CMSC payments going from market participants to the IESO.

It is expected that demand would be a significant driver of CMSC payments. A year with high energy demand should also be a year where the grid's capacities are stretched, and transmission congestion is a more common phenomenon. However, while CMSC payments are positively correlated with demand in Ontario, it is a weak correlation. Figure 3-2 below shows total net CMSC and market demand for each year of the market.

Figure 3-2: Net CMSC and Market Demand[25]
May 2002 – December 2015
($ millions & TWh)

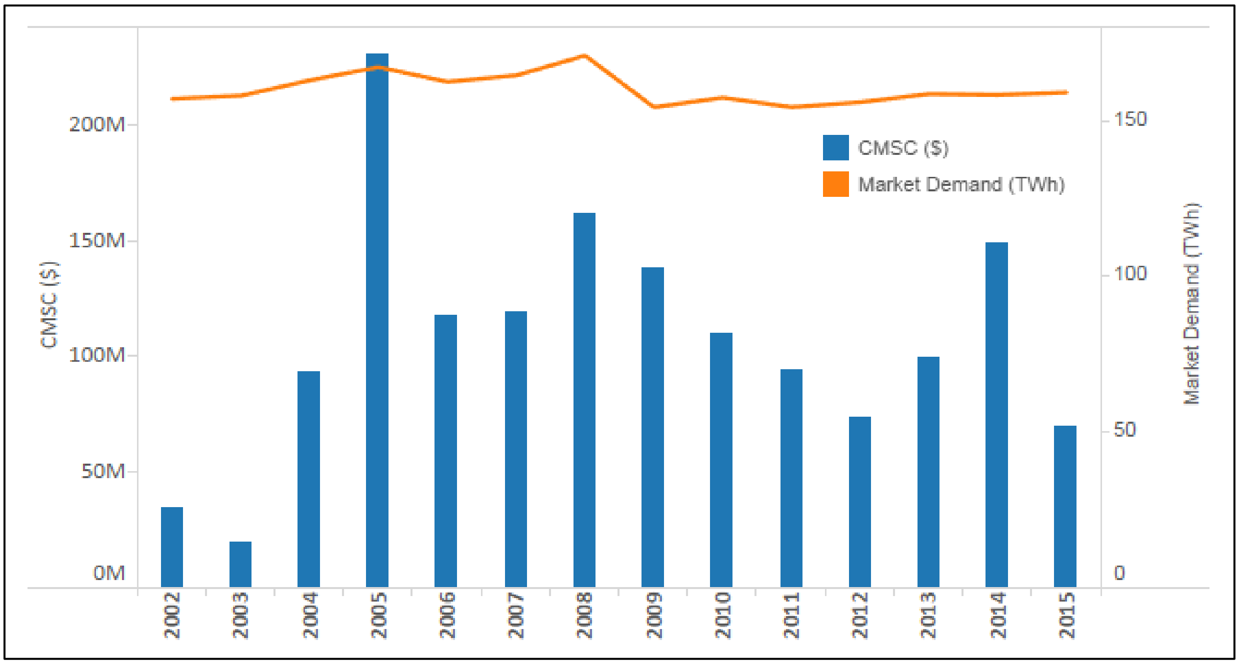


Figure 3-2 shows that net CMSC exhibits much more variability than does market demand. The standard deviation of market demand over the period is, at 5.0 TWh, about 3.1% of its average value, as compared to CMSC's standard deviation of $50.9 million or 44.8% of average CMSC. These numbers are calculated for the years 2003-2015 as 2002 data do not reflect a full calendar year.

[25] Note that the numbers for 2002 do not reflect a full year of market operation. The electricity market opened on May 1, 2002, so the CMSC total reflects data from then to December 31, 2002. The demand number has therefore been pro-rated to reflect a partial year.

3.2 *Transmission vs. Non-Transmission-Related CMSC*

CMSC is frequently paid out under circumstances that have nothing to do with its original intent.[26] This raises the question how much CMSC can be attributed to transmission congestion and how much is driven by other factors such as self-induced CMSC or "gaming" of the CMSC regime.

The Panel estimated the transmission-related vs. non-transmission-related components of CMSC payments. Six days were randomly chosen with the caveat that two days were high demand, two were medium, and two were low demand days. The use of only six days in this estimate is a result of the highly labour-intensive nature of the exercise. Disentangling transmission and non-transmission related CMSC is not a simple matter; the results summarized in Table 3-1 below should be considered rough estimates only.

Table 3-1: Estimates of CMSC Related to Transmission (Tx) Congestion vs. Not Related to Transmission Congestion On 6 Randomly Selected Days ($)

	Generators		Dispatchable Loads		Imports		Exports		Total	
	Tx-Related	Non-Tx-Related	Tx-Related	Non-Tx-Related	Tx-Related	Non-Tx-Related	Tx-Related	Non-Tx-Related	Tx-Related	Non-Tx-Related
Interties	-	-	-	-	116,056	-	378,973	-	495,029	0
Domestic	156,670	651,901	13	107,854	-	-	-	-	156,683	759,755
Total	**156,670**	**651,901**	**13**	**107,854**	**116,056**	**-**	**378,973**	**-**	**651,712**	**759,755**

In this estimate, about 54% of the total CMSC over the 6 days is classified as non-transmission related. This estimate likely understates the amount of CMSC that is non-transmission related for at least two reasons:

- All CMSC payments to importers and exporters are treated as transmission-related. This is a conservative assumption as some of these payments, while related to transmission congestion, may well be inflated due to strategic offer and bid behaviour targeting CMSC payments.[27] An ideal allocation of these payments would show some portion of intertie CMSC as non-transmission related.

[26] The original intent of CMSC is discussed at the beginning of Chapter 2.
[27] This behaviour, known as "nodal price chasing", is discussed in detail in Chapter 4.

- A similar issue arises with CMSC payments to domestic participants. A generator or dispatchable load may be constrained up or down due to transmission congestion, and then alter offer or bid prices to increase the size of CMSC payments. The initial reason for the payments is indeed transmission, but the size of the ultimate payment may reflect non-transmission factors.

Based on the above, and its 14 years of experience monitoring the market, the Panel believes that the non-transmission related component of CMSC payments makes up a significant amount of total CMSC, although the exact quantum is difficult to say. In the Panel's view, it is of concern where a market design originally intended to compensate participants for transmission congestion, pays out a large but uncertain amount of congestion out-of-market payments for reasons unrelated to their intended purpose.

3.3 *CMSC Payments by Market Participant Type*

Table 3-2 shows the breakdown of CMSC payments by type of market participant.

Table 3-2: Net CMSC Payments by Market Participant Type
May 2002 – December 2015
($ millions & %)

	Constrained-off	Constrained-on	Total	Percent
Generators	559.88	383.02	942.90	62.4%
Dispatchable Loads	128.03	5.20	133.22	8.8%
Importers	94.68	110.19	204.88	13.6%
Exporters	175.20	54.69	229.89	15.2%
Total	**957.79**	**553.11**	**1,510.90**	**100.0%**

This table underscores a troubling feature of the CMSC regime. Constrained-off payments heavily outweigh constrained-on payments. The Panel has for a long time held the view that constrained-off payments do not appear to contribute to efficiency, do not appear to have any other credible supporting rationale and are particularly conducive to gaming opportunities.[28]

[28] We note here that constrained-off payments to importers and exporters amounted to 17.9% of total CMSC payments over the time period covered in Table 3-2. These payments have been eliminated as a result of market

3.4 *CMSC Payments by Internal Zone and Intertie*

Table 3-3 below examines CMSC payments by internal zones and interties.

Table 3-3: Net CMSC Payments by Internal Zone and Intertie
May 2002 – December 2015
($ millions & %)

	Constrained-off	Constrained-on	Total	Percent
Internal Zone				
Northwest	240.2	30.8	271.0	25.2%
Northeast	166.1	63.9	230.0	21.4%
Ottawa	3.8	0.0	3.9	0.4%
East	14.3	71.3	85.6	8.0%
Essa	2.5	7.1	9.6	0.9%
Toronto	20.4	80.5	101.0	9.4%
Niagara	81.7	30.9	112.6	10.5%
Southwest	57.1	26.0	83.1	7.7%
Bruce	36.0	-0.2	35.8	3.3%
Western	65.7	77.8	143.5	13.3%
Sub-total, zones	**687.8**	**388.2**	**1076.1**	**100.0%**
Intertie				
Manitoba	104.8	18.9	123.8	28.5%
Minnesota	19.6	41.7	61.3	14.1%
Michigan	24.7	30.3	55.0	12.6%
New York	106.6	19.0	125.6	28.9%
Quebec	14.1	54.9	69.1	15.9%
Sub-total, interties	**269.9**	**164.9**	**434.8**	**100.0%**
Total	**957.8**	**553.1**	**1,510.9**	

One key message in Table 3-3 is the very high percentage of CMSC payments made in the Northwest and Northeast zones. These zones represent very small shares of the load and generation in the province, yet account for almost half of the CMSC paid to participants in internal zones.

rule amendments implemented by the IESO in order to address intertie nodal price chasing. This topic is discussed in Chapter 5.

A similar observation can be made in respect of the CMSC paid at the interties with neighbouring jurisdictions. The Manitoba and Minnesota interties are both located in the Northwest zone and account for a very small percentage of Ontario's trade in electricity, yet they account for almost half of CMSC payments made at the interties.

Chapter 4: CMSC-Driven Wealth Transfers, Inefficiency and Gaming; Fundamental Design Problems

4.1 *Introduction*

This chapter surveys the main themes in the MSP's commentary on the CMSC regime from market opening to the present. There are two broad (but interrelated) themes that have emerged in the MSP's commentary over the past 14 years. The first relates to the wealth transfers and inefficient outcomes that result when market participants take advantage of the CMSC system and adopt strategies designed to increase the size of the CMSC payments they receive.

The second major theme relates to fundamental problems with the Two Schedule System of which CMSC is an integral part. The concern here arises from the wedge the Two Schedule System can place between the cost of supplying electricity, as represented by the local nodal price, and the uniform price used for settlement. As the Panel has noted, when two different prices are both involved in coordinating production and consumption decisions, problems are bound to emerge. This chapter begins the commentary on this subject. Chapter 5 looks at it in more detail where the focus is on the Northwest region. In the Northwest the wedge between nodal prices and the uniform price is very large and the resulting dysfunctions have taken on a systemic character.

The activities underlying these two categories of CMSC payments raise the cost of electricity for all Ontarians without providing commensurate benefits from greater efficiency or reliability.

4.2 *CMSC-Driven Wealth Transfers, Inefficiency and Gaming*

In a Backgrounder issued just prior to market opening, it was noted that "[the Panel] is concerned that some aspects of the congestion management payment system appear to be conducive to gaming, and will monitor behaviour in these areas closely." [29]

The IESO-administered electricity market opened in May 2002 with the Panel's concerns over the Two Schedule System still fresh. The Panel focused its concerns primarily on constrained-

[29] *The Market Surveillance Panel in Ontario's Electricity Market: Monitoring, Investigating, and Reporting*, April 2002, available at http://www.ieso.ca/Documents/marketSurv/ms_MSP_Backgrounder.pdf.

off CMSC which, in the Panel's view, were both hard to justify, and particularly susceptible to gaming.

4.3 *The Panel`s Constrained-off CMSC Consultation*

> *In the opinion of the Panel, if the MCP is sufficient compensation for supplying energy it must also be sufficient compensation for not supply it.* [30]

CMSC payments to suppliers (generators and importers) are based on the difference between the MCP and a supplier's offer price. If a generator is constrained down or off, its CMSC payments become larger, the lower its offer price.

How the CMSC Formula Works for a Supplier (Generator or Importer)

CMSC = (MCP – Offer Price) x (MQ – DQ)

Lost profit per constrained-off MWh   Number of constrained-off MWhs

Some intuition: when a supplier is constrained down the CMSC formula says "You (the supplier) can supply energy at a cost lower than the market price but I (the IESO) have determined that the grid cannot accommodate that electricity. Under the Two Schedule System I will compensate you for your lost profit opportunity with constrained-off CMSC." The lower is the supplier's offer price, the higher is the presumed lost profit on constrained-off output, and therefore the higher the compensation.

The above reflects the original intent of CMSC – compensation for grid congestion. However there are many other reasons why MQ and DQ can differ and the Two Schedule System pays CMSC for all of these other cases.

Note: MCP = market clearing price; MQ = supplier's market quantity schedule; DQ = supplier's dispatch quantity schedule. The formula above is a highly simplified version of the formula actually used to calculate CMSC payments, but it captures the essentials.

[30] *Market Surveillance Panel Report: Constrained Off Payments and Other Issues in the Management of Congestion*, July 2003, page 5, available at http://www.ontarioenergyboard.ca/documents/msp/consultation_ms_cmsc_030703.pdf.

In 2003 the Panel conducted a review and consultation on constrained-off CMSC that produced a discussion paper[31] and a final report.[32] In the discussion paper the Panel reviewed the various arguments put forward for constrained-off CMSC payments, but could not find any scenarios where the payments enhanced the efficient operation of the market. In the Panel's view, significant effects running counter to efficiency were very likely to ensue, for example:

> *…constrained-off payments make it unnecessary for existing generators to consider ways in which they might work to increase transmission capacity to get their product to market. So long as they are receiving their offer price for not producing, they have no incentive to lobby for, or to invest in, expanded or alternative transmission facilities.*[33]

Indeed the Panel's logic expressed above can go further. Given the potential to induce larger constrained-off CMSC payments with low or negative offer prices, generators in an over-supplied region might prefer not to have more transmission capacity built, and the region might be viewed, perversely, as the most desirable location for new generation investment. In other words, normal incentives to lobby for better transmission infrastructure to enable one's product to reach the market can, in the Two Schedule System, go into reverse.

Ultimately, the Panel recommended that constrained-off CMSC payments be eliminated entirely, and short of that, CMSC payments to constrained-off supply resources offering at negative prices be based on a replacement offer price of $0/MWh. This would limit CMSC payments to a maximum of the HOEP for each MWh of energy not produced.

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[31] See Market Surveillance Panel Discussion Paper, *Congestion Management Settlement Credits (CMSC) in the IMO-Administered Electricity Market: Issues related to constrained off payments to generators and imports*, February 2003, available at http://www.ontarioenergyboard.ca/documents/msp/consultation_discussionpaper_180203.pdf.

[32] See *Market Surveillance Panel Report: Constrained Off Payments and Other Issues in the Management of Congestion*, July 2003, available at http://www.ontarioenergyboard.ca/documents/msp/consultation_ms_cmsc_030703.pdf.

[33] Market Surveillance Panel Discussion Paper, *Congestion Management Settlement Credits (CMSC) in the IMO-Administered Electricity Market: Issues related to constrained off payments to generators and imports*, February 2003, page 18, available at http://www.ontarioenergyboard.ca/documents/msp/consultation_discussionpaper_180203.pdf..

4.4 *The IESO's 2003 Urgent Market Rule Amendment*

The IESO implemented the Panel's recommendation to replace negative offer prices for constrained-off CMSC purposes in an urgent market rule amendment made in June 2003. The IESO's move was partly in response to unfolding events as in early 2003 a generator market participant began to earn very large constrained-off CMSC payments based on negative offer prices.

As part of this urgent rule amendment the IESO characterized the original intent of CMSC payments:

> *The original intent of CMSC payments within the regime of Ontario uniform pricing is to keep a market participant whole with respect to the profit implied by its market schedule where the market participant has been subject to a constraining dispatch instruction and thereby encourage compliance with dispatch instructions.*[34]

This statement of the original intent of CMSC is different from the intent expressed by the Market Design Committee in its Final Report of June 29, 1999. The key difference in the IESO's statement is that it is not referenced to *transmission congestion*, and therefore seems to leave open the possibility of paying CMSC when there is a difference between the market and dispatch schedules *caused by any reason*. As this report has shown, the original, limited mandate for CMSC payments as expressed by the Market Design Committee has given way to a greatly expanded set of reasons for paying it.

4.5 Self-induced CMSC

> *With respect to CMSC payments induced by dispatch deviation, the CMSC results from the participant's own action and is not attributable to any system characteristics. It is in fact compensation for non-compliance and is particularly hard to justify.*[35]

[34] Urgent market rule amendment MR-00239-R00, *Eliminate CMSC Payments Associated with Negative Priced Offers*, June 26, 2003, page 2, available at http://www.ieso.ca/Documents/mr/mr_00239-R00_URAC.pdf.
[35] Market Surveillance Panel Discussion Paper, *Congestion Management Settlement Credits (CMSC) in the IMO-Administered Electricity Market: Issues related to constrained off payments to generators and imports*, February 2003, page 23, available at
http://www.ontarioenergyboard.ca/documents/msp/consultation_discussionpaper_180203.pdf.

Perhaps no other topic has attracted the Panel's attention as frequently as self-induced CMSC. Self-induced CMSC are CMSC payments that arise because of technical limitations of the participant or actions of the participant, and not because of congestion on the IESO-controlled grid.

A participant can induce CMSC by taking an action that causes its market schedule and dispatch schedule quantities to differ. CMSC gets paid automatically even though transmission congestion was not the cause of the difference in the schedules. Moreover, the participant can magnify the effect of the schedule difference on the size of its CMSC payments by altering its offer or bid price to widen the differential between the market price and its offer or bid price.

The simplest route to self-induced CMSC is "dispatch deviation" where a participant fails to accurately follow its dispatch instruction.[36] Examples are ramping to a new output (or consumption) level at a rate somewhat slower than instructed; or delaying the start of a ramp by a few intervals. Even more obvious is to run at a flat output level that is somewhat different from the instructed level.

The Panel proposed that all such CMSC payments be stopped. The IESO responded with a market rule amendment in December, 2003, "…which effectively states that a dispatchable load facility is not entitled to CMSC resulting from the facility's own equipment or operational limitations"[37] but did not create the mechanisms to fully implement this principle. Self-induced CMSC has continued to be a major concern of the Panel through the life of the market.

Generators were not subject to this rule amendment as the IESO held that the computation of self-induced CMSC for generators would be too complex.[38]

[36] Some variation around the dispatch instruction is permitted, referred to as the "compliance dead band". See Market Rule Interpretation Bulletin IMO- _MKRI_0001, available at http://www.ieso.ca/imoweb/pubs/interpretBulletins/ib_IMO_MKRI_0001.pdf.

[37] Market Surveillance Panel June 2004 Monitoring Report, page 102, available at http://www.ontarioenergyboard.ca/documents/msp/panel_mspreport_imoadministered_140604.pdf. Also see the IESO's Market Rule Amendment Proposal (December 2003), available at: http://www.ieso.ca/Documents/Amend/mr/mr_00195-R00-R06_BA.pdf.

[38] Market Surveillance Panel June 2004 Monitoring Report, pages 102-103, available at http://www.ontarioenergyboard.ca/documents/msp/panel_mspreport_imoadministered_140604.pdf.

The Panel's July 2008 Monitoring Report (for the period October 2007 to April 2008) noted growing instances of self-induced CMSC payments to generators via dispatch deviations.[39] This observed behaviour contradicted the fundamental rationale for CMSC that it ensures reliability through dispatch compliance.

The July 2008 Monitoring Report noted that dispatch deviations by generators were becoming a more regular feature of the market. Also, the Panel noted that constrained-off CMSC was now typically about $7.6 million per month, or about 60% higher than constrained-on CMSC at $4.8 million per month. The Panel reiterated its recommendation for the IESO to review constrained-off CMSC with a view to its discontinuation.

4.6 *Ramp-down CMSC*

The price a generator offers when shutting-down may be strategic.[40]

The above quote from the Panel's January 2009 Monitoring Report is the Panel's first comment on *ramp-down CMSC* and, in hindsight, a classic of understatement. This issue would grow to become the most frequently discussed CMSC matter addressed by the Panel. The report noted that fossil fired generators were able to induce sizable CMSC payments each time they "ramped" output down. Over a two year period from December 2006 to November 2008 gas-fired generators induced almost $6.9 million in CMSC payments while ramping down to the end of their production run.

Ramp-down CMSC is a result of the 3-times ramp rate assumption in the market schedule which causes schedule differences, and CMSC payments, whenever a facility is ramping to a different level of output or consumption. It also reflects the assumption in the market rules on CMSC calculation that market participants offer and bid at marginal costs of production or marginal benefits of consumption.

Ramp down CMSC is also a prime example of CMSC mission creep. When the IESO began to stakeholder a solution to ramp-down CMSC in 2015 generators argued that they faced higher

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[39] Market Surveillance Panel July 2008 Monitoring Report, pages 203-205, available at http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/msp_report_200807.pdf.

[40] Market Surveillance Panel January 2009 Monitoring Report, page 214, available at http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/msp_report_200901.pdf.

operating costs when ramping down at the end of their production day, and that the associated CMSC was a legitimate compensation for these extra costs. This concept was embedded in the ultimate solution to ramp-down CMSC that, in the Panel's view, effectively recreates ramp down CMSC under a different name.

4.6.1 Ramping Down Generators

There are two ways that generators come offline in Ontario's wholesale electricity market. A generator may be dispatched off by the IESO's scheduling algorithm as demand declines and/or other less expensive sources of supply are available, thereby rendering the generator's offers no longer economic. Alternatively, generators sometimes choose the point in time at which they want to come offline for their own business reasons. This can be achieved by submitting an offer price higher than its usual operating offer in order to increase the likelihood that the generator is not scheduled in the constrained dispatch schedule.

As the generator ramps down its market schedule drops faster than its dispatch schedule because of the 3-times ramp rate assumption. The resulting constrained-on CMSC payments are larger the higher is the generator's offer price. Thus the generator can use its offer price when ramping down to influence the size of its CMSC payment – and, when ramping down, the generator is not subject to any competitive discipline to keep its offers close to its marginal cost. Some generators employed extremely high offer prices when ramping down and garnered very large CMSC payments as a result.

4.6.2 The Panel's Monitoring Document and the IESO's Recent Rule Amendments

The Panel's January 2010 and August 2010 Monitoring Reports repeated concerns about ramp-down CMSC and noted that ramp-down CMSC payments were continuing at a rate of $1 million per month. The Panel also reiterated previous calls for the IESO to pursue a rules-based solution to this form of self-induced CMSC.[41]

In August 2011 the Panel released a Monitoring Document that provided guidance to market participants regarding the level of offer prices that would not normally trigger a gaming

[41] Market Surveillance Panel August 2010 Monitoring Report, pages 271-273, available at http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_20100830.pdf.

investigation if a generator raises its offer price to signal an intention to come offline for *bona fide* business reasons. These offer prices would nevertheless ensure, with a high degree of certainty, that the generator would be scheduled to come offline.

Most generators responded by lowering the offer prices they used to signal their intention to come offline. The Panel's April 2012 and June 2013 Monitoring Reports noted sizeable reductions in ramp-down CMSC payouts by as much as two-thirds of the total. However, the June 2013 Monitoring Report also noted that ramp-down CMSC payments were continuing, albeit at a much reduced level, and that the bulk of the continuing payments were related to offer prices that exceeded the guidance provided in the Panel's Monitoring Document.

In February 2015 the IESO presented a market rule amendment submission to its Technical Panel that outlined a rules-based solution to ramp-down CMSC. After some refinements carried out by the Technical Panel, the IESO's proposal was adopted by the IESO Board on June 24, 2015. This rule amendment came into effect in December 2016.

The IESO's approach replaces CMSC for ramping down generators with an alternative payment mechanism called the "ramp-down settlement amount" which is the lesser of conventional CMSC or a "ramp-down settlement amount" amount (RDSA). RDSA is calculated in a similar fashion to CMSC. However, a major difference is that the generator's offer price is replaced with its offer price from the hour before ramp-down begins multiplied by 1.3.[42] The hour before ramp-down offer price is intended to reflect the generator's steady state cost of operating and to be free of any inflation of the offer intended to self-induce higher CMSC payments.

The Panel has indicated a degree of concern about the potential for generators to game this approach to ramp-down CMSC possibly by submitting artificially slow ramp rates. The IESO has indicated that it will work closely with the Panel to monitor outcomes associated with this rule amendment. The IESO indicates that it would propose further clawback capabilities in the market rules for some generators who raise their offer prices in the hour preceding ramp-down.

[42] More specifically, the 1.3 multiplier applies to MWs below the generator's Minimum Loading Point (MLP). Offers on MWs above the MLP are not multiplied.

4.7 *Gaming*

4.7.1 The Panel's Framework for Gaming Investigations

The Panel describes its framework for gaming investigations in the following way:

> "The Panel's mandate includes investigations in relation to conduct that may constitute an abuse of market power or gaming. In the course of providing a framework for analyzing market power issues, the Panel has noted that gaming is a separate concept (which may or may not overlap with market power concerns) that encompasses, among others, market manipulation and conduct that involves the following four elements:
>
> - a defect in the market design, poorly specified rules or procedures or a gap in the Market Rules or procedures (collectively referred to as a market defect);
> - exploitation of the market defect by the market participant;
> - profit or other benefit to the market participant; and
> - expense or disadvantage to the market." [43]

The Panel has completed two investigations that found gaming had occurred. The first one concerned a gas-fired generating station located near Sarnia, Ontario. The second concerned two dispatchable loads. In both cases the amounts of money found to have been gamed by the market participants related largely to CMSC paid during ramping periods.

Market Defects Identified in Investigations

The market defects identified in the two investigations were very similar. They were the self-induced CMSC Defect (CMSC is paid for all schedule differences, whatever the cause); and the assumptions that offer and bid prices reflect marginal cost and benefit. The specifics of these market defects were discussed in Chapter 2.

[43] See Market Surveillance Panel, *Report on an Investigation into Possible Gaming Behaviour Related to Infeasible Import Transactions Offered by West Oaks NY/NE LP on the Manitoba-Ontario Intertie*, available at http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Investigation_WestOaks_20121022.pdf, and Market Surveillance Panel, *Report on an Investigation into Possible Gaming Behaviour Related to Infeasible Import Transactions Offered by TransAlta Energy Marketing Corp. on the Manitoba-Ontario Intertie*, available at http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Investigation_TranAlta_20121022.pdf, both released October 22, 2012.

The Greenfield Energy Centre Investigation[44]

The Panel investigated three distinct behaviours carried out by Greenfield Energy Centre LP (GEC) in 2010-2011 and found that two of them did not constitute gaming as there were reasonable explanations for why they were carried out. However, the third behaviour – submission of an increased offer price to signal intent to shut down – was found to be gaming. The Panel found that GEC's high offer prices had resulted in a profit or benefit of about \$432,000 in CMSC payments. While GEC did not agree with the Panel's findings, it voluntarily repaid the amount to the IESO.

The Abitibi and Bowater Investigation[45]

In this case the Panel found that Abitibi-Consolidated Company of Canada and Bowater Canadian Forest Products Inc., two affiliated dispatchable loads located in the Northwest, had self-induced a total of \$20.4 million in CMSC payments. They achieved this through different behaviours, including by inducing differences between their market and dispatch schedules and setting extremely high bid prices in order to guarantee very large CMSC payments. This was mostly done via ramping – changing from one level of consumption to another – and taking actions to cause the schedule differences to persist longer than otherwise would be the case.

The two dispatchable loads represent only about 20% of Ontario's dispatchable load capability but the \$20.4 million paid to them compares to \$590,000 of net CMSC payments made to all other dispatchable loads in Ontario over the same period – in other words these two dispatchable loads received 97% of the CMSC paid to all dispatchable loads.

4.8 *Some Inefficient Outcomes Related to CMSC Payments*

> *A regime, such as the present one, in which we sell energy at one price while producing it at another price is bound to be problematic.*[46]

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[44] Market Surveillance Panel, *Report on an Investigation into Possible Gaming Behaviour Related to Congestion Management Settlement Credit Payments by Greenfield Energy Centre LP*, July 2014, available at http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Investigation_Greenfield_20140717.pdf.

[45] Market Surveillance Panel, *Report on an Investigation into Possible Gaming Behaviour Related to Congestion Management Settlement Credit Payments by Abitibi-Consolidated Company of Canada and Bowater Canadian Forest Products Inc.*, February 2015, available at http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Investigation_Report_CMSC_Abitibi_Bowater_2015.pdf.

Economists are quick to take note of any situation where a wedge is driven between the price consumers of a good or service pay, and the costs at the margin of producing that good or service. This situation is one of inefficiency – there are gains from trade that are not being fully exploited, either because too little or too much of a commodity is produced and consumed.

This phenomenon is built into the Two Schedule System and then compounded by the CMSC system of congestion out-of-market payments. The price – cost wedge will drive its own set of inefficient outcomes as will the availability of the out-of-market payments themselves. The next few sections look at some examples.

4.8.1 CMSC-driven Inefficiencies at the Interties

Inefficient Exports to New York

The Panel's June 2006, December 2006, and August 2007 Monitoring Reports analyzed in detail the phenomenon of inefficient exports on the New York intertie.[47] The inefficiency associated with these transactions is a direct consequence of the discrepancy between the price that an exporter pays to buy power– the uniform HOEP[48] – and the cost of supplying that electricity for export. In the reports the Panel distinguished between privately efficient and socially efficient exports. An export to New York is privately efficient if the price at which an exporter buys power (the HOEP) is lower than the price in New York at which the exporter sells power. The same export may be socially inefficient if the true cost of supplying that export is higher than the New York delivered price.[49]

[46] Market Surveillance Panel December 2006 Monitoring Report, page 110, available at http://www.ontarioenergyboard.ca/documents/msp/msp_report_final_20061222.pdf.
[47] Market Surveillance Panel June 2006 Monitoring Report, pages 68-79, available at http://www.ontarioenergyboard.ca/documents/msp/msp_report_final_130606.pdf. Market Surveillance Panel December 2006 Monitoring Report, pages 104-110, available at http://www.ontarioenergyboard.ca/documents/msp/msp_report_final_20061222.pdf. Market Surveillance Panel August 2007 Monitoring Report, pages 145-153, available at http://www.ontarioenergyboard.ca/documents/msp/msp_report_20070810.pdf. The focus in these Monitoring Reports on New York should not be understood to mean that the problem was absent at other interties. The Panel merely focussed on this intertie.
[48] An exporter is able to buy at HOEP as long as the intertie is uncongested. If the intertie is congested the intertie price will diverge from the HOEP.
[49] As the New York electricity market has a location marginal pricing design there is no wedge in that market between the price and cost – at least on account of a two schedule design.

Between January 2004 and October 2006 the Panel found that just under 70% of exported energy to New York was privately efficient, while under 50% was socially efficient. The Panel points out that the inefficient exports phenomenon is "…just one of the inefficiencies that can occur when the HOEP…differs from the incremental cost of energy at a given point in the province."[50]

Inefficient Imports into the Northwest[51]

Over the period from January 2009 to October 2010 there were 2,722,936 MWh of imports in the unconstrained schedule at the Manitoba intertie. Eighty-one percent of these imports were constrained off and thus were paid CMSC to not provide energy to Ontario.[52] Of the remaining 741,535 MWh of imports that were actually in the constrained schedule – thus providing energy to Ontario - 71% or 528,798 MWh of these were inefficient in that they could have been sold to Minnesota and earned a price higher than the value of the energy in Ontario.

[50] Market Surveillance Panel December 2006 Monitoring Report, page 104, available at http://www.ontarioenergyboard.ca/documents/msp/msp_report_final_20061222.pdf
[51] Market Surveillance Panel February 2011 Monitoring Report, page 79, available at http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_20110310.pdf.
[52] That such a high percentage of these market schedule imports were constrained off is indicative of "nodal price chasing" – a topic we will return to.

Chapter 5: Systemic Problems in the Northwest

5.1 Introduction

> *The Panel has repeatedly reported on large CMSC payments made to market participants in the Northwest region, even though the area accounts for only a small portion of the total Ontario generation and load…The CMSC payments are major contributors to zonal prices which do not reflect actual marginal or opportunity costs of production or consumption.*[53]

The problems identified in the previous chapter with regards to Ontario's Two Schedule System are amplified to a systemic level in the Northwest.

The region's significant imbalance between abundant energy supply, modest demand, (see Figure 5.1 below) and insufficient transmission capacity and export opportunities has created surplus supply conditions in the area. This surplus supply has led to persisting gaps between nodal prices in the region – the prices that are intended to reflect the true cost of supplying electricity on a locational basis – and the province-wide uniform MCP. As the Panel has noted many times in the past, this pattern of prices drives inefficient market outcomes and creates gaming opportunities that cause inappropriate transfers of wealth which, in turn, raises the cost of energy for the province as a whole.

The opportunity to exploit the nodal price / uniform price gap seems most easily available to energy traders – those entities active in the import and export of energy.

This chapter surveys the problems in the Northwest and the measures taken to address them. The remainder of this introduction provides a bulleted list of anomalous observations from the Northwest, and some high level explanation:

- Of the $1.5 billion in CMSC payments made since market opening, the Northwest zone has attracted almost one third of this total[54], despite holding only 4% of Ontario's

[53] Market Surveillance Panel February 2011 Monitoring Report, page 70, available at http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_20110310.pdf.

[54] Table 3-3 shows that CMSC paid to market participants in relation to internal transactions amounts to about 25% of total internal CMSC since market opening. If intertie CMSC is included, then CMSC paid to participants in the Northwest accounts for 30% of total CMSC since market opening.

generation capacity. Meanwhile, demand in the region has fallen to roughly 2% of total Ontario demand.[55]

- Nodal prices in the Northwest – the prices that are intended to reflect the true cost of supply in the region – have persisted at negative levels for several years. It is as if to say that generators must pay large amounts of money in order to produce a product that has positive economics costs; and that consumers must be paid to use a product they clearly value. In economic terms such outcomes are nonsensical – they cannot represent a lasting real economic equilibrium.
- Despite the above indications of excess supply and negative nodal prices, generators and importers in the region receive average effective prices, inclusive of CMSC payments, that exceed what generators and importers in the rest of the province receive. For importers in particular, the discrepancies between effective prices in the Northwest and the rest of the Province can be quite large.[56]
- At the same time, dispatchable loads in the Northwest pay average effective prices that are discounted by the CMSC payments they receive. In the case of the dispatchable loads that were the subject of the Panel's gaming investigation, the CMSC payments were large enough to completely offset the prices they paid to consume electricity, effectively paying them to consume.[57]
- Non-dispatchable loads in the region pay the same higher price as loads elsewhere in Ontario, despite the excess supply of power in the Northwest and the low or negative shadow prices. Thus these customers do not benefit from the low cost of power in the region.

[55] Market Surveillance Panel January 2010 Monitoring Report, page 89, available at http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/msp_report_201001.pdf.
[56] Market Surveillance Panel February 2011 Monitoring Report, pages 70-73, available at http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_20110310.pdf. As a result of the MR-00395-R00 market rule amendment this is changing. See discussion later in this chapter.
[57] Market Surveillance Panel February 2011 Monitoring Report, pages 70-73, available at http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_20110310.pdf. See Chapter 4 for a summary to the Panel's investigation into these two loads.

- A trader at an intertie in the Northwest can experience profitable arbitrage opportunities for trades in both export and import directions at the same time, at the same intertie.[58]
- Exporters in the region are able to bid at low prices for energy to export, be constrained on, and get paid CMSC at a high enough level to more than offset their cost of energy exported – they are paid to export.
- The interties in the region (with Manitoba and Minnesota) have frequently exhibited congestion in the market schedule in the import direction; however, since market opening up to Fall, 2009, more than half of these congested hours have had no imports actually flowing.[59] In fact, actual power can flow in the *export direction* in the dispatch schedule, even when the intertie is import-congested in the market schedule.
- Imports of "phantom power" - one type of nodal price chasing behaviour where import offers into the Northwest are designed to be constrained off and receive CMSC payments – are included in the market schedule for the whole province, thus depressing market clearing prices everywhere in the province and distorting energy production and consumption decisions.

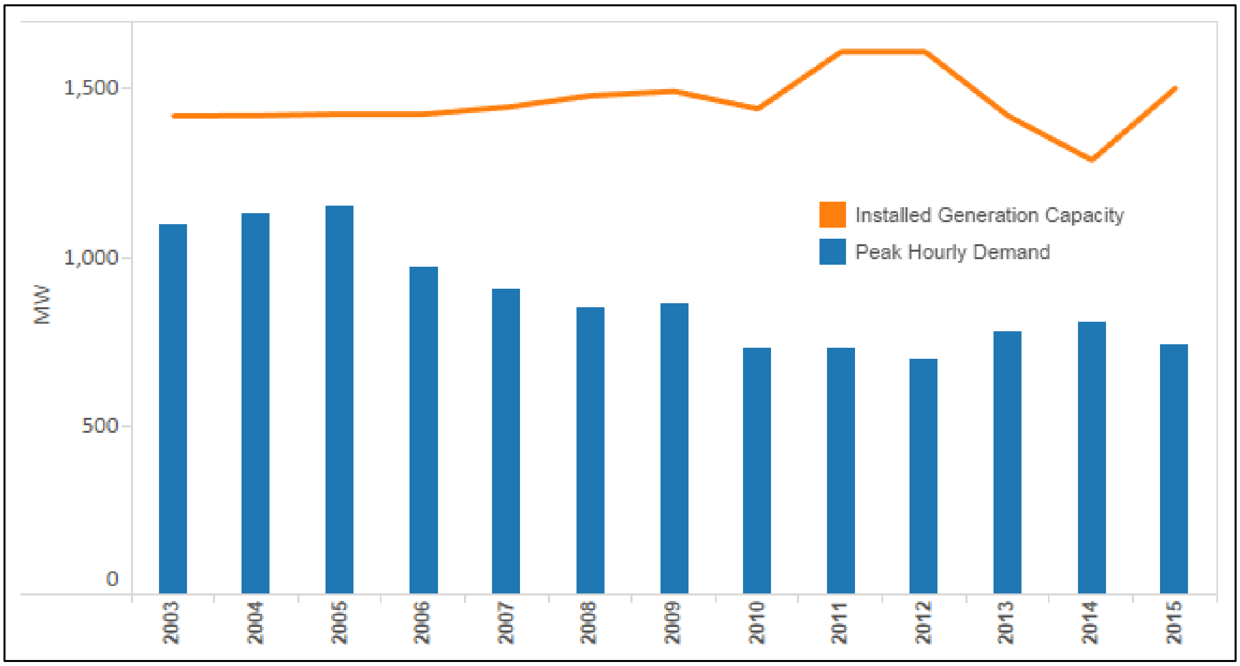
There are two fundamental factors that, in combination with the Two Schedule System, drive the wedge between nodal prices in the Northwest and the province-wide MCP, and allow for the above outcomes in the Northwest:

- The Northwest contains excess supply in that it lacks the transmission capacity and export opportunities to send energy to neighbouring jurisdictions and/or the rest of Ontario. In other words, the Northwest has significant bottled generation.
- The region's endowment of generation capacity includes a significant component of hydroelectric generation that has very limited storage ability and, at certain times, cannot be spilled.[60] In other words, it must run. Hydroelectric generators that must run will

[58] Market Surveillance Panel June 2006 Monitoring Report, page 80-82, available at http://www.ontarioenergyboard.ca/documents/msp/msp_report_final_130606.pdf.
[59] Market Surveillance Panel January 2010 Monitoring Report, pages 95-96 and pages 99-100, available at http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/msp_report_201001.pdf.
[60] Spilling water – diverting it from the turbines – is never an attractive option as the energy is therefore lost for nothing. For many of these generators spilling is not an option at all due to safety and environmental reasons; in some cases the spill pathways are separated from the operations facility itself, meaning the operator cannot be sure

offer at prices as low as necessary, even if deeply negative, to ensure they are scheduled in the dispatch schedule. This is financially viable because these generators are not paid the negative nodal prices their situation and actions help create. Rather they are paid the uniform MCP, a price set largely by supply and demand in the rest of the province.

Figure 5-1: Supply & Demand Imbalance in the Northwest
January 2003 – December 2015
(MW)



The resulting large discrepancies between the low nodal prices in the region and the province-wide MCP create incentives for market participants in the region to target CMSC payments:[61]

- The remaining generators in the Northwest region can target constrained-off CMSC by lowering their offer prices to a range above the prevailing nodal prices (to ensure they are constrained off) but well below the MCP (to ensure as large as possible of a CMSC payment).

that other people are not in the area and hence at risk. As a result the operators are obliged to run the water through their turbines.

[61] Market Surveillance Panel February 2011 Monitoring Report, pages 70-73, available at http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_20110310.pdf.

- Importers can essentially do the same as generators but without the burden of actually managing physical generation assets. Thus imports are offered at very low prices, but not low enough to be dispatched. These offer strategies of local generators and importers, along with the strategies of loads and exporters described below, are collectively known as "nodal price chasing behaviour."
- Dispatchable loads can bid to buy at low prices – below the MCP so they are left out of the market schedule – but above the nodal price to ensure they are constrained on and are thus paid CMSC. This may result in very low effective prices for these loads, and thus may induce inefficiently high consumption of electricity. This would, in turn, reinforce the subsidy to local generation assets by artificially increasing the demand they face.[62]
- Exporters can employ a strategy similar to that of dispatchable loads: bidding to buy at low or negative prices and getting paid significant constrained-on CMSC to export power.

The various scenarios in the Northwest that have been analyzed in Panel reports are, for the most part, specific manifestations of the dynamics outlined above. The rest of this chapter discusses the highlights of the Panel's commentary.

5.2 Nodal Price Chasing Behaviour

> *Upon further review the [Market Assessment Unit] noted that participants could structure their bids and offers into known congested zones so as to receive a stream of CMSC payments with little likelihood of ever delivering energy into the Ontario market.*[63]

The above quote is from the Panel's first comment on nodal price chasing behaviour in the Northwest. During the summer of 2005 the Panel observed that some market participants were receiving large CMSC payments by structuring import offers into the congested zones so as to be constrained off. Due to persistently low nodal prices in the area, importers on the two interties

[62] Market Surveillance Panel November 2011 Monitoring Report, pages 134-138, available at http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_20111116.pdf. .
[63] Market Surveillance Panel December 2005 Monitoring Report, page 72, available at http://www.ontarioenergyboard.ca/documents/msp/msp_report%20final_131205.pdf.

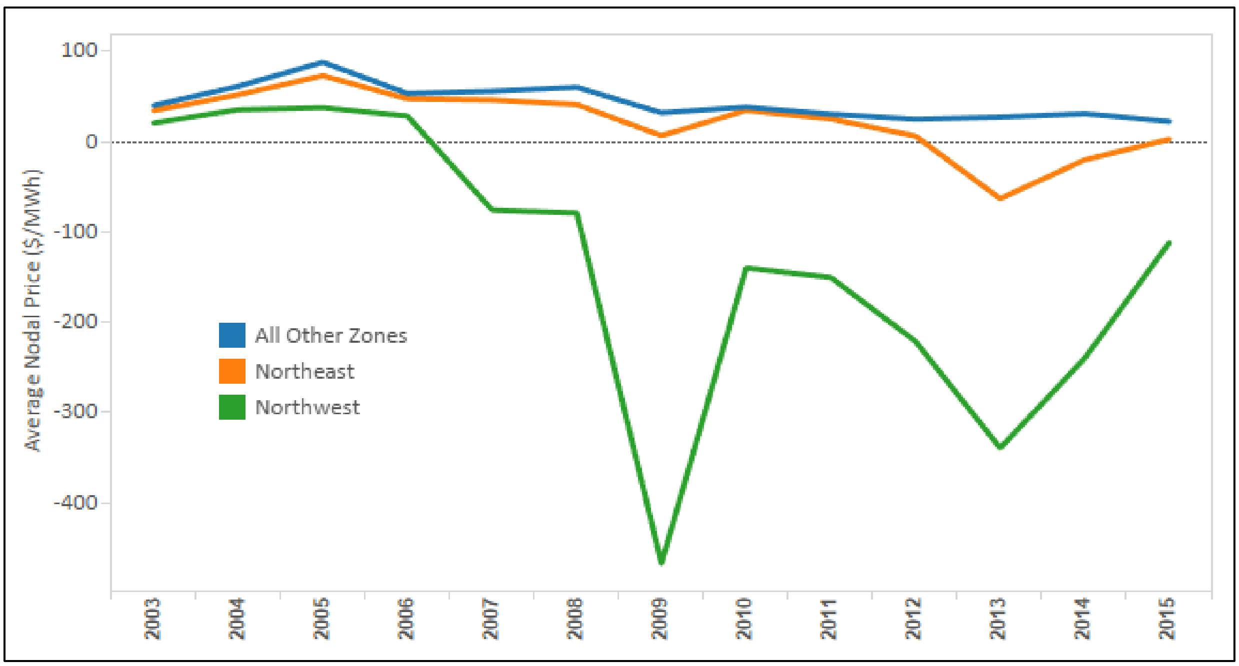
into the Northwest were especially able to employ this strategy. However, market rule amendments that became effective in October, 2012 all but eliminated constrained-off CMSC payments to importers in the Northwest. The results have been dramatic. Before we describe the new competitive environment on the Northwest interties, we review developments in the years from 2005 to 2012.

5.2.1 The Emergence of Negative Nodal Prices

> *For the first time we are observing Northwest zonal prices which are consistently negative over the period of review.*[64]

The Panel's December 2007 Monitoring Report noted the emergence of negative nodal prices as a persisting phenomenon in the Northwest during the summer of 2007. This was attributed to continually falling demand and an abundance of hydroelectric supply in the region and in neighbouring jurisdictions.

Figure 5-2: Trends in Annual Average Nodal Prices by Zone
January 2003 – December 2015
($/MWh)



[64] Market Surveillance Panel December 2007 Monitoring Report, page 39, available at http://www.ontarioenergyboard.ca/documents/msp/msp_report_20080115.pdf.

Figure 5.2 above shows nodal prices in Ontario's 10 internal zones on an annual average basis.[65] Of note is the steep drop in Northwest nodal prices beginning in 2007 and reaching a nadir in 2009. As lower water levels and hence reduced hydroelectric capacity emerged after 2009, Northwest nodal prices recovered from their lowest levels, but remain deeply negative. The wedge in the Northwest between nodal prices and the MCP, and the resulting nodal price chasing behaviour, underlie all of the above mentioned anomalous outcomes in the Northwest.[66]

5.2.2 A Systemic View of the Problem

The Panel's January 2010 Monitoring Report began a series of in-depth commentary on the Northwest. Referring to the nodal price chasing we have discussed thus far, the Panel pointed out:

> *…the uniform pricing system in Ontario…coupled with the CMSC payments arising from the constrained schedule has distorted generators' and importers' incentives to offer at their incremental or opportunity cost and has provided an incentive for exporters to bid strategically low in certain situations.*[67]

Beginning in 2007 constrained-off CMSC paid to importers in the Northwest began to run in excess of constrained-off payments to internal generators. Thus importers in the Northwest were getting paid more to not supply energy than were the generators who actually had responsibility for physical generation assets.[68]

5.2.3 Intertie Congestion with No Energy Flowing

The January 2010 Monitoring Report also noted the frequency with which the interties in the Northwest experience import congestion in the market schedule. This occurred in 6,701 hours from May 2002 to October 2009, or about 10.2% of all hours since market opening. In more

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[65] In zones other than the Northwest and Northeast there is very little variation in average nodal prices, so all of these zones have been averaged together.
[66] Market Surveillance Panel November 2011 Monitoring Report, pages 134-138, available at http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_20111116.pdf.
[67] Market Surveillance Panel January 2010 Monitoring Report, page 90, available at http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/msp_report_201001.pdf.
[68] Market Surveillance Panel January 2010 Monitoring Report, page 92, available at http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/msp_report_201001.pdf.

than half of these hours there was no actual net import energy flowing on these interties.[69] Indeed, often there were actual net flows of energy in the opposite – export – direction despite the intertie being congested in the import direction in the market schedule.

These outcomes – an artifact of the Two Schedule System – are problematic from efficiency and wealth transfer perspectives. The market schedule outcome shows import congestion at the intertie as if importers are eager to take advantage of favourably high prices in Ontario. Their supplies of "phantom energy" serve to lower the HOEP and drive local nodal prices even lower. However, in the dispatch schedule, actual energy flows the other way suggesting the traders can actually buy cheaply in Ontario to profit from actual export sales. The "phantom" imports increase this tendency. While the energy may actually flow in the efficient direction on net, with all these distortions to price signals it is unlikely that trade is carried on in the most efficient volumes. Additionally, all of these transactions involve constrained-on and -off scenarios with CMSC payments that can be very high. Generators and importers are paid not to produce or supply energy, while exporters actually get paid to buy the energy they export. All of these costs are ultimately paid by Ontario ratepayers.

By the time of the Panel's January 2014 Monitoring Report (covering the winter 2012-2013 period) market schedule import congestion got worse. In its analysis of the October 2012 market rule change the Panel found that over the two year period from October 2010 to September 2012 the Northwest interties were import congested at least 30% of the time. And, as before, this did not imply any energy was actually flowing into the Northwest.

5.2.4 Arbitrage Opportunities in Both Directions

> *Normally an arbitrager exports when the Ontario price is low…and imports when the Ontario price is high…The situation in the Ontario market is different. The Ontario market has two price sequences, a uniform price and a constrained price. These two*

[69] An interesting side-effect of this occurred in the IESO's transmission rights market. Transmission rights in Ontario are financial instruments that pay the holder when an intertie is congested in the direction of the right that is held. This payment is based on market schedule congestion. However, transmission rights are funded by congestion rents at the interties that reflect the price differences between Ontario and neighbouring intertie zones when there is actual physical congestion on the intertie. This source of funding for the transmission rights market does not exist when no energy is actually flowing on the intertie. The funding shortfall has to be recovered from transmission rights auctions revenue – therefore less of this revenue can be rebated back to Ontario consumers.

different price sequences can lead to two directly opposite arbitrage opportunities at the same time. A trader can profit from both arbitrage opportunities at the same time.[70]

In most markets an arbitrage opportunity will tend to go in only one direction at a time – from the low-priced region to the high-priced region. However, in Ontario's electricity market, any wedge between nodal prices and the uniform MCP allows for arbitrage in both directions. In its January 2010 Report the Panel observed this at the Manitoba intertie where market schedule imports were constrained off the vast majority of the time as they were offered at prices below the HOEP but above the relevant shadow prices in the Northwest.[71] Significant amounts of constrained off CMSC were paid as a result.

This same trader was also paid significant amounts of constrained-on CMSC for exporting power outside of Ontario over the Minnesota intertie. This can be achieved by bidding to buy power at a low price under the MCP but above the nodal price. The export will not be scheduled in the market schedule because the bid price is too low. However, the bid to buy power will be constrained on in the dispatch schedule if the bid price is above the relevant nodal price. Thus a trader can offer to import and bid to export with both deals at the same price and get paid CMSC on both of them.

The transaction that actually flows (in other words, that is constrained on in the dispatch schedule) is usually the efficient one in that it moves energy from low to high priced regions.[72]

5.2.5 CMSC and Effective Prices

Another window into the systemic nature of the CMSC problem in the Northwest is its effect on the average effective prices paid by load participants and received by suppliers in the Northwest versus the rest of the province. The Panel's February 2011 Monitoring Report provided analysis of this for the summers of 2009 and 2010 (see Table 5.1 below).

[70] Market Surveillance Panel June 2006 Monitoring Report, page 80, available at http://www.ontarioenergyboard.ca/documents/msp/msp_report_final_130606.pdf.
[71] Market Surveillance Panel January 2010 Monitoring Report, pages 97-104, available at http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/msp_report_201001.pdf.
[72] This is, however, not always the case as we saw in Chapter 4.

Table 5-1: Average Effective Prices Received or Paid by Market Participant Class in the Northwest and the Rest of Ontario Summer 2009 & Summer 2010[73] ($/MWh)[74]

Participant Type	Summer 2009			Summer 2010		
	Average Revenue Received / Paid			Average Revenue Received / Paid		
	Northwest	All Other Areas	Ontario	Northwest	All Other Areas	Ontario
Generators	26.18	26.13	-	43.78	42.13	-
Importers	97.16	28.94	-	56.06	42.68	-
Dispatchable Loads	11.70	21.92	-	(0.95)	31.94	-
Exporters	5.36	24.03	-	25.21	39.86	-
Non-Dispatchable Loads	-	-	27.17	-	-	42.78

For suppliers (generators and importers) these effective prices are calculated as energy market revenues received plus CMSC payments, all averaged over the quantity of energy supplied. Generators in the Northwest receive average effective prices slightly higher than generators in the rest of the province. For importers, however, those in the Northwest are substantially better off than those in the rest of the province, especially in the summer of 2009 when Northwest nodal prices were at their steepest discount and importers were receiving substantial constrained-off CMSC payments. This is another example of a perverse economic outcome: importers in the Northwest – a region where energy is in excess supply – get paid much more than importers elsewhere in the province per unit of energy actually imported.

On the demand side, effective prices are calculated as energy payments made net of CMSC received, then averaged over the quantity of energy consumed. In the Northwest both dispatchable loads and exporters paid effective prices substantially lower than their counterparts in the rest of the province.

Dispatchable loads, wherever located in Ontario, paid much less on average than non-dispatchable loads in Ontario.[75]

[73] 'Summer' refers to the months of May through October, inclusive.
[74] Market Surveillance Panel February 2011 Monitoring Report, page 71, available at http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_20110310.pdf. These calculations exclude Global Adjustment and other non-CMSC uplift charges, as well as generator cost guarantee payments.
[75] Note that this result is not reflective of the High-5 Global Adjustment allocation which has benefited "Class A" loads. Table 5.1 covers a period before the High-5 came into effect, and, in any case, does not include the GA component of payments for energy. It reflects only the ability of dispatchable loads to offset energy costs with

5.2.6 IESO Responses

Since market opening the IESO has made several changes to the market rules that are intended to limit the amounts of unwarranted CMSC payments. In many cases these rule changes have been as a result of specific recommendations made in Panel reports. This section surveys the most important of these changes.

The $0 replacement for negative priced offers - 2003

As noted in Chapter 4, in 2003 the Panel recommended the outright elimination of constrained-off CMSC payments, but failing that, the use of a replacement offer price of $0/MWh for all negative generator and import offer prices. This would have the effect of limiting constrained-off CMSC to an amount equal to the HOEP for each MWh not produced. The IESO implemented this in June 2003 for all generators and importers in the province.

Demand side replacement bids - 2010

The demand side of the market – dispatchable loads and exporters – can employ nodal price chasing strategies as well as the supply side can. In the demand side case, buyers also bid a negative price targeting a level below the MCP – so that they will be "uneconomic" in the market schedule – but above the local nodal price – so that they will be constrained on. The resulting CMSC payments can be very large if the nodal price is very low and the buyer successfully places its bid just above the nodal price.

In 2010 the IESO addressed this form of nodal price chasing. Negative bid prices from dispatchable loads and exporters were replaced, but not with the value of $0/MWh as is done for constrained-off CMSC for suppliers. Rather the IESO set replacement bids of -$50/MWh for dispatchable loads and -$125/MWh for exporters.[76] These replacement bids allow for

CMSC payments – something non-dispatchable loads cannot do. For more on High-5 see Market Surveillance Panel June 2013 Monitoring Report, pages 69-92, and the Appendix to this Report, available at http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_May2012-Oct2012_20130621.pdf.

[76] See market rule amendment MR-00370, *Limiting CMSC Payments for Exporters and Dispatchable Loads*, available at http://www.ieso.ca/Documents/Amend/mr2010/MR-00370-R00-BA.pdf. This rule amendment became effective in December 2010.

considerable amounts of constrained-on CMSC payments to be made to these classes of market participants.[77]

What was the IESO's rationale for choosing these replacement prices? For exporters there was a concern that a replacement bid of $0/MWh would frustrate potentially efficient exports at negative prices into neighbouring jurisdictions that also had negative prices for energy, but at a higher level than the negative nodal prices in the Northwest.

The Panel considered that this analysis had merit if the negative nodal price in the Northwest actually reflected the marginal costs and marginal benefits of energy production and consumption in the region. This, however, is a questionable assumption given that both demand side and supply side participants in the Northwest can get paid significant CMSC payments for negative-priced bids and offers, and, for suppliers, not actually be exposed to the resulting negative nodal prices.

In the case of the -$50/MWh replacement price for negative bids from dispatchable loads, the motivation had to do with the additional charges that dispatchable loads pay when consuming a unit of energy production. These include Global Adjustment charges and uplifts, which amounted to roughly $50/MWh. It is not at all clear why the CMSC calculation should be designed to allow dispatchable loads, through negative bid prices, to recover the other charges normally attached to the purchase of energy, and which other loads pay as a matter of course. Using CMSC to allow dispatchable loads to recover these charges appears to be another example of CMSC mission creep.

In any case, the rationale for the Global Adjustment component of the -$50/MWh replacement bid disappeared when the revised Global Adjustment Allocation formula went into effect in January 2011. Under the revised "High-5" allocation methodology, Class A loads (which include all dispatchable loads) do not pay a marginal (i.e. volumetric) charge for Global Adjustment. As a result the Panel recommended in its November, 2011 Monitoring Report that the dispatchable load replacement bid price be revised to not take into account any Global

[77] Market Surveillance Panel November 2011 Monitoring Report, pages 134-141, available at http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_20111116.pdf.

Adjustment charges. The IESO did revise the replacement bid price to -$15/MWh in March, 2012.

Eliminating CMSC to importers in the Northwest - 2012

> *Implementation of the October 2012 market rule change has eliminated the incentive for importers to chase nodal prices in the NW…*[78]

In 2012 the IESO took a big step in the direction of the Panel's original recommendation to eliminate constrained-off CMSC: it implemented a market rule amendment that eliminated constrained-off payments to importers in the Northwest when those transactions are constrained-off in the final pre-dispatch run.[79]

The virtual elimination of constrained-off CSMC to importers in the Northwest has had dramatic effects on the behaviour of participants in the region, and on market outcomes. The Panel's January 2014 Monitoring Report provides a detailed analysis of how several market metrics have responded to this change. Following the rule change, all of the metrics moved decisively in a direction consistent with the elimination of the incentive to chase nodal prices.

Constrained-off payments to importers were all but eliminated at the Manitoba intertie, and were fully eliminated at the Minnesota intertie. Before the rule change importers at the Manitoba intertie regularly offered imports at a price much lower than the prices available in the Mid-Continent Independent System Operator (MISO) market. The prices available in the MISO market are a measure of the opportunity cost of imports as importers would pay this price to source the imported energy, or could have sold energy to MISO at that price rather than sell to Ontario.

That importers would offer to import at prices deeply discounted from this opportunity cost suggests these offers were intended to be constrained off and not actually flow. After the rule

[78] Market Surveillance Panel January 2014 Monitoring Report, page 134, available at http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Nov2012-Apr2013_20140106.pdf.
[79] See market rule amendment MR-00395-R00, *Limiting Constrained Off CMSC Payments to Imports into Designated Chronically Congested Areas*, approved by the IESO Board of Directors on September 7, 2012 and in effect on October 1, 2012), available at http://www.ieso.ca/Documents/Amend/mr2012/MR-00395-R00_Amendment_Proposal_v5_Board_Approved.pdf.

change import offer prices typically exceeded the external opportunity cost price, indicating that importers were targeting a profit on an import actually intended to flow. The changes pre and post were in the same direction at the Minnesota intertie.

Market schedule import congestion occurred in about one third of all hours in the period before the rule change at the Manitoba intertie, and was just under this proportion at the Minnesota intertie. At both interties import congestion fell to less than 1% of hours after the rule change.

The January 2014 Monitoring Report includes several other market indicators that also show changes consistent with a greatly reduced incentive for importers to chase nodal prices, and a move towards more competitive and efficient outcomes.

Export Nodal Price Chasing – Eliminating Constrained-Off CMSC at All Interties

The Panel's April 2015 Monitoring Report[80] contained an extensive analysis of export nodal price chasing and showed that it was occurring at all Ontario interties – not just those in the Northwest. The analysis contained several examples of exporters whose bid prices did not reflect current domestic pricing nor the prices available in the external jurisdictions where the exports would be sent. What the exporters' bid prices did reflect was an attempt to be constrained off and maximize CMSC payments by bidding at prices that were above the HOEP but below the intertie nodal price.

The April 2015 Monitoring Report presented several examples of this behaviour drawn from all five of Ontario's intertie locations. The Panel also estimated the total of CMSC overcompensation arising from export nodal price chasing at all interties from January 2013 to April 2014 was $21.8 million.

The IESO reacted very soon after the release of the April 2015 Monitoring Report. In May, 2015 it launched a stakeholder engagement exercise whose purpose was the elimination of all constrained-off CMSC at all Ontario interties. The associated market rule amendment was approved by the IESO Board in August, 2015 and became effective on September 18, 2015. This may turn out to be the single biggest piecemeal fix for unwarranted CMSC payments.

[80] Market Surveillance Panel April 2015 Monitoring Report, pages 119-151 and Appendix 3A, available at http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Nov2013-Apr2014_20150420.pdf.

5.3 *Conclusion*

The IESO has concluded that there must be a more fundamental reform of Ontario's wholesale electricity market, and has begun a process to do so. The Panel supports this initiative and the history of Panel commentary on problems with the Two Schedule System and CMSC payments provides the reasons why. There is simply too much inefficiency and opportunities for gaming of CMSC payments in a market design "…in which we sell energy at one price while producing it at another price…"[81]

The adoption of some form of locational pricing for the IESO-administered electricity market is important for other reasons as well. The Panel has recently been engaged in work on the costs and inefficiencies associated with the real-time generation cost guarantee program.[82] This work provides support to proposals for Ontario to develop a day ahead market, because this design would allow for more efficient trading of electricity with Ontario's neighboring jurisdictions. It would facilitate determining Ontario's exports as well as imports on a day ahead basis and thus greatly improve the efficiency of Ontario's daily unit commitment – the decisions relating to what generation units should start for the day to supply energy.

Thus a day-ahead market would be a highly desirable advance in market design for Ontario. However, logic and past experience strongly suggest that a day ahead market design must include locational prices. Note that a day ahead market would not replace the real time market but rather would coexist with it.[83] In the mid-2000s the IESO attempted to develop a day ahead market in Ontario that featured a uniform price, two schedules, and CMSC payments - like the existing real time market. The resulting design, with congestion payments calculated for both day ahead and real time markets, turned out to be too complex, and the initiative was abandoned.

The essential point here is that there are gains to be had from further evolution of the Ontario wholesale electricity market – but the sequence matters. And the first step in that sequence is the

[81] Market Surveillance Panel December 2006 Monitoring Report, page 110, available at http://www.ontarioenergyboard.ca/documents/msp/msp_report_final_20061222.pdf.
[82] The Panel's work in relation to this program is summarized in its November 2016 Monitoring Report, available at http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_May2015-Oct2015_20161117.pdf.
[83] In jurisdictions that have a day ahead market, the real time market continues to exist as a balancing market to cover deviations from the day ahead outcome and supply and demand in real time. Most energy is, however, transacted on the basis of the prices and quantities determined day ahead.

replacement of the current Two Schedule System with a locational pricing market design for the real time energy market.

Glossary

Bottled generation: "Bottled" generation is generation that is located in a region where there is more generation present than load, and there is also insufficient transmission capacity leading from the region to allow the surplus generation to be fully utilized. Thus there is excess supply of generation capacity relative to load. Nodal prices in a region with bottled generation will typically be lower than average for the market as a whole.

CMSC: This is an acronym for *congestion management settlement credits,* which are out-of-market payments made to suppliers (generators and importers) and dispatchable consumers (dispatchable loads and exporters) in the IESO-administered markets. CMSC is paid to these participants whenever they are constrained on or off. They are constrained on or off whenever their market schedule and dispatch schedule quantities are different.

Constrained-off dispatch instruction: The IESO issues dispatch instructions to all dispatchable generators and loads every 5 minutes (and hourly to importers and exporters). The dispatch instructions have both a market schedule quantity to produce or consume, and a dispatch schedule quantity. If a participant's market schedule quantity is greater than its dispatch schedule quantity the participant has been "constrained off" or "constrained down". This dispatch instruction will generate a constrained-off CMSC payment to the participant in question.

Constrained-on dispatch instruction: This is a dispatch instruction similar to the one described above but where the market scheduled quantity is less than the dispatch scheduled quantity.

Efficiency / Inefficiency: Inefficiency is a concept in economic theory where the marginal costs and marginal benefits of an activity are misaligned so that gains from trade are not fully exploited. An allocative inefficiency occurs when the relative price paid by consumers for a good or service is not aligned with its relative marginal cost so either "too much" or "too little" of the good or service is produced and consumed. A productive inefficiency occurs when the relative marginal products of factors of production (land, labour, capital etc.) are not aligned with their relative costs (land rents, wages, capital rental rates etc.) so that the factors of production are not employed in optimal proportions. A dynamic inefficiency occurs when returns to investment are not aligned with the costs of capital so either "too little" or "too much" investment in a certain form of capital takes place. Inefficiencies can be caused by tax distortions, other interventions such as price floors and ceilings imposed by government, or market failures (for example pollution externalities, information asymmetries, natural monopoly, market power, and public goods).

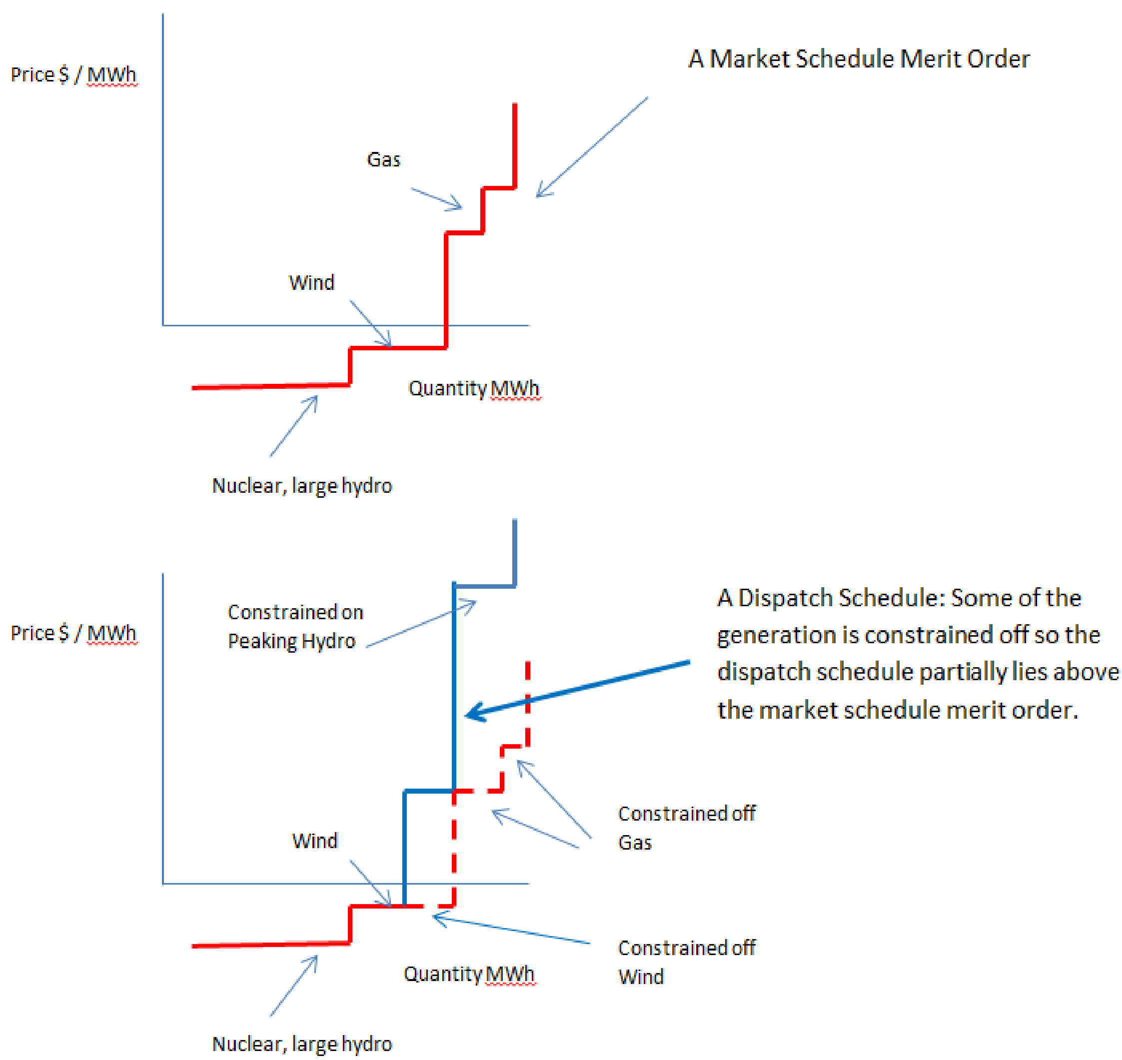
Two forms of inefficiency mentioned in this report are dispatch inefficiencies, and inefficient exports. A dispatch inefficiency can occur if a generator alters its offer price away from its true marginal cost so as to target CMSC payments with the result that the dispatch algorithm moves away from the merit order. Thus a more expensive generator would be dispatched before a less expensive generator.

An inefficient export can occur when an exporter pays the uniform MCP to purchase energy for export at a higher price in the foreign jurisdiction but the true cost of the energy, as measured by the nodal price nearest the export intertie, is higher than both the MCP and the foreign received price.

Market Defect: A market defect is a defect in the market design, poorly specified rules or procedures or a gap in the market rules or procedures that creates opportunities for exploitation by market participants without necessarily involving breaches of market rules. The notion of a market defect is an element of the Market Surveillance Panel's gaming investigation framework. Gaming is said to occur where the Panel finds that a market defect exists and was exploited by a market.

An example of a market defect that is relevant to this paper is the assumption – when it is unwarranted - that market participants make offers and bids that reflect their marginal costs of production or marginal benefits of consumption. Offers and bids sometimes do not reflect marginal costs and benefits, especially when participants are strategically targeting CMSC payments. Any resulting CMSC payments will therefore likely over-compensate the participants.

Merit order: The "Merit Order" is the supply stack or supply curve in the market schedule. It ranks generator offers in order from lowest to highest without regard to internal congestion constraints that may prevent certain offers from being accepted in the dispatch schedule.



Must-run generator: A generator that finds itself financially non-viable may make application to the IESO for de-registration from the IESO-administered markets. However, if the IESO determines that de-registration of the facility would have an unacceptable impact on the reliability of the IESO-controlled grid, the IESO may enter into negotiations with the participant for a Reliability Must Run contract, that would compensate the facility for the reliability benefits it provides. A generator operating under such a contract is a "must-run generator".

The same expression is used in this report to describe a hydroelectric generator who for safety or environmental reasons cannot spill its water and must run the water through its turbines in order to generate electricity. There are several such "must-run generators" in the Northwest region of the province.

Nodal price: A nodal price measures the costs to the system incurred as a result of a 1 MWh increase in consumption of electricity at a particular node, or, connection point on the grid. Nodal prices may be different than the uniform market clearing price because of congestion. If a certain transmission line is congested then achieving a 1 MWh increase in consumption at a particular node that is on the far side of the congestion constraint may require replacing some cheaper generation with more expensive generation. This pushes up the system cost at that node.

Nodal price chasing behaviour: Nodal prices are used to determine the dispatch schedule quantities of production and consumption on the grid. A generator is considered to be "economic" in the market schedule if its offer price is less than the uniform market clearing price (MCP). However, it may be "uneconomic" in the dispatch schedule if the relevant nodal price at the generator's connection point is lower than the MCP and lower than the generator's offer price. This generator will be constrained off and receive a constrained-off CMSC payment. If the generator expects this price configuration to arise it can maximize its CMSC payment by setting its offer price just above the relevant nodal price. In the Northwest region in particular, generators and importers have been observed to structure their offer prices in this manner, thus guaranteeing that no energy need be delivered, and a CMSC payment will be made to them. Such structured offers are called "nodal price chasing behaviour". Disaptchable loads and exporters can also engage in nodal price chasing strategies.

Privately efficient: The producer of a commodity or service finds a sale of a unit of that commodity or service to be "privately efficient" if the costs incurred by the producer to create and sell that unit are less than the price received. In other words, the sale is privately profitable.

Ramp rate: The rate at which a generator or load can change from one level of production or consumption to a different level of production or consumption. For example, if a generator can move from a production level of 50 MW at the beginning of a 5 minute dispatch interval to 100 MW at the end of the 5 minute dispatch schedule, the generator has a ramp rate of 10 MW per minute.

RMR contract: A Reliability Must Run (RMR) contract is a contract negotiated between the IESO and a generator that would otherwise opt to de-register its facility. If the IESO finds that de-registration of the facility would impose an unacceptable reliability impact on the IESO-controlled grid, it will enter into negotiations with the generator for a contract that will provide sufficient compensation to the generator in return for remaining in service.

Self-induced CMSC payments: CMSC payments are generated for a participant whenever that participant's market schedule quantity and dispatch schedule quantity differ. If the difference in the two schedules results from technical limitations of the participant's facility, or the participant's own actions, rather than congestion conditions on the grid, the CMSC payment is said to be self-induced.

Socially efficient: The sale of a unit of a commodity or service is considered to be "socially efficient" if the costs incurred by both the producer of the unit and all other persons who directly or indirectly bear any costs caused by the production and sale of the unit are less than the value of the unit to its consumers. For example the production and sale of a MWh of electricity is socially efficient if the marginal costs to the producer of the product plus the costs of any environmentally harmful emissions resulting from the production and sale of the MWh are less than the value of the MWh.

The context in which this term is used in this report has to do with socially inefficient exports of electricity at the interties. An export may be privately efficient if the exporter buys the energy for the export at the MCP and sells it at a foreign price that is high enough to cover the MCP and any transactions costs. However the export may be socially inefficient if the nodal price that is nearest to the location of the export is higher than the MCP and high enough (with transactions costs figured in) to exceed the value of the export in the foreign market. The Panel's reports have shown that the percentage of all exports that are socially inefficient can be quite high.

Transmission congestion: Transmission lines have thermal and security limits that system operators respect when dispatching generation and load and thus determining the power flows along the transmission lines. When the power flows approach these limits the transmission lines become congested. In order to increase the supply of energy to load beyond these congestion points the system operator must re-dispatch generation and load in ways that do not violate the limits.

Uniform price, two-schedule market design: The uniform price, two schedule market design is the electricity wholesale market design used in Ontario. It consists of two dispatch algorithms: the market algorithm and the dispatch algorithm. The market algorithm balances electricity supply and demand assuming no internal congestion constraints, and determines the uniform MCP used for settlement purposes. The dispatch algorithm recognizes internal congestion constraints and re-dispatches generation and dispatchable load so as to respect all constraints. The "supply curve" in the dispatch schedule will in general lie above the supply curve in the market schedule as the dispatch algorithm is obliged to constrain on more expensive generation and constrain off less expensive generation as compared to the market algorithm.